G 24244
SN: 13827 *
13828

In Reply Refer To: MS 5232

03 JUL 2002

Mr. Craig W. Dickerson
Shell Offshore Inc.
Two Shell Plaza
Post Office Box 2648
Houston, Texas 77252-2648

Dear Mr. Dickerson:

Reference is made to the following application that has been reviewed by the Minerals Management Service:

Application Type: New Right-of-Way Pipeline
Application Date: April 23, 2002

Work Description: Create 200-foot wide right-of-way and install, operate, and maintain the following:

One 10-inch by 16-inch pipe-in-pipe, 6.87 miles long, to transport bulk oil from Kepler Well K-1, Sled N2 in Block 383, Lease OCS-G 07937, through Blocks 384, 385, to Ariel Well A-4, Sled N3 located in Block 429, Lease OCS-G 07944, all of which is located in the Mississippi Canyon area.

Assigned Right-of-Way Number: OCS-G 24244
Assigned Segment Number: 13827
Outer Casing Number: 13828

Pursuant to 43 U.S.C. 1334(e) and 30 CFR 250.1000(d), your application is hereby approved.

The approval is subject to the following:

Our review indicates that the routes to be taken by boats and aircraft in support of your proposed activities are located in or could traverse Military Warning Area W-453. Therefore, please be advised that you will contact the Air National Guard-CRTC, Gulfport/ACTS, Gulfport, Mississippi 39507 [contact TSgt. D. Crawford or TSgt. L. Wyche at (228) 867-2433] concerning the control of electromagnetic emissions and use of boats and aircraft in Military Warning Area W-453.

Your request to use navigational positioning equipment to comply with Notice to Lessees and Operators No. 98-20, Section IV.B, is hereby approved.

Assigned MAOP (psi): 5,590
MAOP Determination: Subsea Segment No. 13831, Hydrostatic Test Pressure of Pipeline.

Please be reminded that, in accordance with 30 CFR 250.1008(a), you must notify the Regional Supervisor at least 48 hours prior to commencing the installation or relocation of a pipeline or conducting a pressure test on the pipeline. Also, in accordance with 30 CFR 250.1008(b), you must submit a report to the Regional Supervisor within 90 days after completion of any pipeline construction.

Sincerely,

(Orig. Sgd.) J. R. Hennessey

Donald C. Howard
Regional Supervisor
Field Operations

bcc: 1502-01 Segment No. 13827, ROW OCS-G 24244 (MS 5232)
/ 1502-01 ROW OCS-G 24244 (Microfilm) (MS 5033)
1502-01 Segment No. 13828, ROW OCS-G 24244 (MS 5232)
1502-01 ROW OCS-G 24244 (Microfilm) (MS 5033)
MS 5250 New Orleans District w/flow schematic
MS 5232 Cartography

TMeyer:amm:07/03/02:Shell Offshore Inc.-13827

MICRO

10" 13827
13828
(G 24244)

#5

Shell Offshore Inc.

Two Shell Plaza
PO Box 2648
Houston TX 77252-2648

HAND DELIVERY

April 23, 2002

APR 26 2002

Mr. Alex Alvarado (MS 5232)
Minerals Management Service
1201 Elmwood Park Boulevard
New Orleans, LA 70123-2394

OFFSHORE MISSISSIPPI AND ALABAMA
NAKIKA SUBSEA DEVELOPMENT
PROPOSED NAKIKA NORTH 10″X16″ PIP BULK OIL
BIDIRECTIONAL PIPELINE – PERMIT #5
BETWEEN KEPLER WELL K-1 SLED N2 IN MISSISSIPPI
CANYON BLOCK 383 AND ARIEL WELL A-4 SLED N3 IN
MISSISSIPPI CANYON BLOCK 429
PERMIT APPLICATION NO. 5 – NAKIKA NORTH BULK OIL

Dear Mr. Alvarado:

Pursuant to the authority granted in 43 U.S.C. 1334 (e) and the Regulations contained in Title 30 CFR 250, Subpart J, Shell Offshore Inc. ("Shell") is filing this application, in quadruplicate, for a right-of-way two hundred feet (200′) in width for the construction, operation, and maintenance of a proposed 10″X16″ PIP bidirectional bulk oil pipeline between Kepler Well K-1, Sled N2 in Mississippi Canyon Block 383 and Ariel Well A-4 Sled N3 in Mississippi Canyon Block 429, a distance of 36,259 feet or 6.87 miles, all in offshore federal waters, Gulf of Mexico. Shell agrees that said right-of-way, if approved, will be subject to the terms and conditions of said regulations.

The expected start of construction of the pipeline is August 2002. All construction will be accomplished with the use of a dynamically positioned vessel. The onshore base of operation will be Mobile, Alabama. The operator of the pipeline will be Shell Offshore Inc.

In accordance with applicable regulations, the applicant has delivered a copy of the application and attachments thereto by certified mail, return receipt requested, to each lessee or right-of-way or easement holder whose lease, right-of-way or easement is affected. A list of such lessees or right-of-way or easement holders is attached hereto as Attachment "A", and copies of the return receipts showing the date and signature as evidence of service upon such lessees or right-of-way or easement holders will be forwarded to your office when received.

In accordance with applicable regulations, we enclose with this application a 3-1/2 inch computer disk containing the digital pipeline location data in fixed-format ASCII file for the flowline and four copies of the following materials:

1. Design Criteria
2. Vicinity and Survey Plat Maps-Flowline (5 sheets)
3. Nakika General Field Arrangement (Figure 1)
4. Field Layout (North) Mississippi Canyon Block 383 to 474 (00-012-1000-P Rev.A)
5. Overall Field Layout - 10″X16″ PIP Oil Flowline Loop – Color Code for Permit Applications (00-012-1200-A)
6. 10″X16″ PIP Oil Flowline Loop – Illustration of Pipe Segment for #5 Permit Application (00-012-1205-A).
7. Oil (10″X16″ PIP) Flowline Loop – Safety Schematic and Flowline Diagram – Subsea (MC-383) to Nakika Host (MC-474) (00-012-3002-A)

The 10″X16″ Nakika North bulk oil pipeline survey report is included in the overall survey report for the Nakika North Flowline Project and submitted with Permit Application #1.

Enclosed is an Equilon Pipeline company LLC draft in the amount of $2,455.00 of which $2,350.00 covers the application fee and $105.00 covers he first year rental on 6.87 miles of right-of-way.

The design of the flowline and jumpers are in accordance with the Department of the Interior Title 30 CFR 250 Subpart J and API – RP 1111. Shell also agrees to the following stipulation:

STIPULATION

Shell Offshore Inc. hereby agrees to keep open at all reasonable times for inspection by the Minerals Management Service, the area covered by this right-of-way and all improvements, structures, and fixtures thereon and all records relative to the design, construction, operation, maintenance and repairs or investigations or with regard to such area.

Please refer to your New Orleans Miscellaneous File Number 0689 for a copy of Shell Offshore Inc.'s charter and authority for the undersigned as Attorney-in-Fact of Shell Offshore Inc. to sign for and on behalf of Shell Offshore Inc.

If the above and attached information meets with your approval, please issue the necessary permit for the right-of-way at your earliest convenience. Inquiries concerning this application may be directed to W. Craig Dickerson at (713) 241-3485. Technical inquiries may be directed to the following:

Flowlines: Bruce Light (281) 544-2863

Please return the approval letter to the attention of Mr. W. Craig Dickerson, Room TSP 1352 at the letterhead address above.

Very truly yours,

D. M. Melesurgo, Attorney-in-Fact

AB/cjm

Enclosures

cc: <u>Shell International E&P Inc.</u>
J. M. Korpal, Process Manager (WCK 2360)
Bruce Light, Project Engineer (WCK 2330)
Lynn Wang, Pipeline Engineer (WCK 2337)
T. A. Preli, Staff Engineer (WCK 2366)

<u>w/enclosures</u>
<u>Shell Exploration & Production Company</u>
M. W. (Mark) Davis, Sr. Engineering Technician (OSS 3412)
M. J. (Mike) Mire, Sr. Engineering Technician (OSS 864)

UNITED STATES
DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

NON-DISCRIMINATION IN EMPLOYMENT

As a condition precedent to the approval of the granting of the subject pipeline right-of-way, the Grantee, Shell Offshore Inc., hereby agrees and consents to the following stipulation that is to be incorporated into the application of said right-of-way.

During the performance of this grant, the grantee agrees as follows:

> During the performance under this grant the grantee shall fully comply with paragraphs (1) through (7) of section 202 of Executive Order 11246, as amended, (reprinted in 41 CFR 60-1.4 (a)), which are for the purpose of preventing discrimination against persons on the basis of race, color, religion, sex or national origin. Paragraphs (1) through (7) of section 202 of Executive Order 11246, as amended, are incorporated in this grant by reference.

Shell Offshore Inc.

Signature of Grantee
D. M. Melesurgo, Attorney-in-Fact

ATTACHMENT A

PROPOSED NAKIKA NORTH 10X16-INCH BULK OIL FLOWLINE – Permit #5

Lessees/Operators

Area/Block	O&G Lease No.	Operator(s)/Lessee(s)
MC383	OCS-G 7937	Shell Offshore Inc.
MC385	OCS-G 7938	Shell Offshore Inc.
MC429	OCS-G 7944	Shell Offshore Inc.
MC384	OPEN	----------

MMS PERMIT APPLICATION
NaKika North Oil Flowline Permit #5: Kepler Well K-1 to Ariel Well A-4 and Umbilicals

FLOWLINE DESIGN SUMMARY

NaKIKA NORTH FIELDS (Kepler and Ariel):
PIPE-IN-PIPE FLOWLINE LOOP;
ELECTRIC, HYDRAULIC AND
CHEMICAL INJECTION UMBILICALS

Mississippi Canyon Block 383
to
Mississippi Canyon Block 474 (NaKika Host)

Prepared by
Shell International Exploration and Production, Inc. (SIEP) for

Shell Offshore, Inc.

March 2002

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LIST OF FIGURES

I. INTRODUCTION - NaKIKA FIELD DEVELOPMENT

The NaKika Field is located some 144 miles southeast of New Orleans, Louisiana in water depths ranging from 5,800 feet to 7,000 feet. The field is composed of five independent, sub-economic fields that were discovered between 1987 and 1997. The five fields: Kepler (MC-383), Ariel (MC-429), Fourier and Herschel (MC-522), and East Anstey (MC-607) will be co-developed via subsea tiebacks to the centrally located NaKika host facility at MC-474 for fluids processing and export via pipelines. Kepler, Ariel, and Herschel fields are predominately oil while Fourier and East Anstey fields are predominately gas. An overview of the Na KIKA Field Arrangement is shown in Figure 1.

The Ariel and Kepler fields are in the NaKika north field. There are total five wells with three dispersed wells at Ariel and two clustered wells at Kepler. The general field arrangement of NaKika North Field is illustrated in Figure 2 and has the following features:

- A total of 5 (five) segments of 10-inch x 16-inch electrical heated Pipe-In-Pipe (PIP) flowlines are used to transport the oil by forming a single "piggable" loop interconnecting all five wells. The flowlines terminate at the NaKika host as two catenary risers using flexible-joint fittings. The flowlines and risers are approximately 25.3 miles in length and in water depths ranging from 5800' to 6350'.
- Each production riser also has a dedicated gas-lift sled and gas lift riser to improve production rates, reservoir recovery, and flow stability (slug suppression).
- Five umbilicals having metal tubes and electric conductors provide hydraulic power, annulus vent, electrical service, and chemical injection to the Ariel/Kepler subsea system.

The schedule for installation of the North field pipelines is as the following:

Table 1. North Flowline and Riser Installation Schedule

Description	Scheduled Data	Installation Method
Flowlines	August 2002	J-Lay by Coflexip Stena Offshore
Risers	April 2003	J-Lay by Coflexip Stena Offshore
Gas Lift Risers	May 2003	Reel-Lay by Coflexip Stena Offshore
Umbilicals	March – May, 2003	Reel-Lay by Halliburton Subsea

The flowlines will be installed by the J-Lay method by Coflexip Stena Offshore Limited using their dynamically positioned pipelay barge Deep Blue. The umbilicals will be installed by Halliburton Subsea using their lay vessel Toisia Perseus. There are no third party pipeline crossings along the proposed route of north flowline loop.

A deep tow survey of the proposed route for each flowline was conducted in August 2001. The results of the survey are presented in a geotechnical assessment report prepared by Geomatrix Consultants, Inc. dated November 2001 entitled "Geologic Assessment for Proposed Flowlines Area North, Mississippi Canyon 383 to 474, Nakika Pipeline Project, Northern Gulf of Mexico"

1. *Survey Synopsis*

As assessed in the *Geologic Assessment for Proposed Flowlines Area South Mississippi Canyon 383 to 474 Nakika Pipeline Project – Northern Gulf of Mexico* produced by Geomatrix in January of 2002, the deeptow data shows no evidence of hard-bottom conditions, seafloor faulting, fluid expulsion features, or any other potential geologic or archeological hazard along the intrafield flowline or umbilical routes.

While some faults associated with fluid expulsions areas were identified in MC-476, MC-477, MC-520, & MC-521, the intrafield flowlines and umbilicals avoid these areas completely. No faults or fluid expulsion areas were identified within 3,000 ft of the proposed intrafield flowline or umbilical routes and there is no evidence to show than any chemosynthetic communities exist along any of the proposed routes. There is a small mudflow area to the Northwest of the Kepler wells; however, this does not pose a risk to the North intrafield flowline and umbilicals.

There are no obstructions or man-made structures along the routes. Some man made features (i.e. Drilling mud splays) occur along the routes, but do not present a hazard to installation or operations of the intrafield flowlines or umbilicals.

As concluded in the above report, "There is no evidence for adverse geologic conditions, obstructions, chemosynthetic communities, or cultural features either on the seafloor or at depth along any of the proposed routes that would preclude the routing of an intrafield flowline or umbilical."

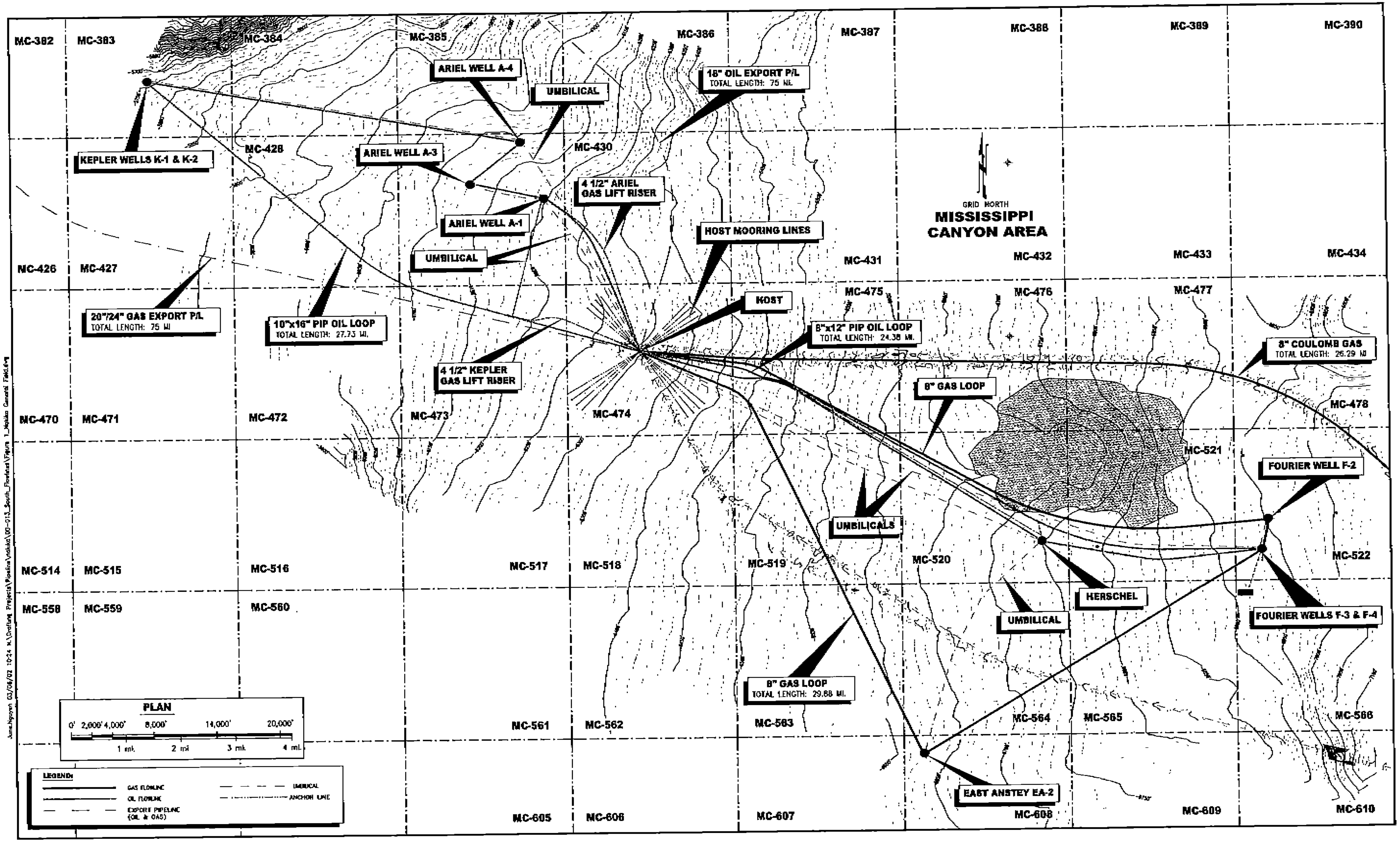

Figure 1. NaKiKa General Field Arrangement

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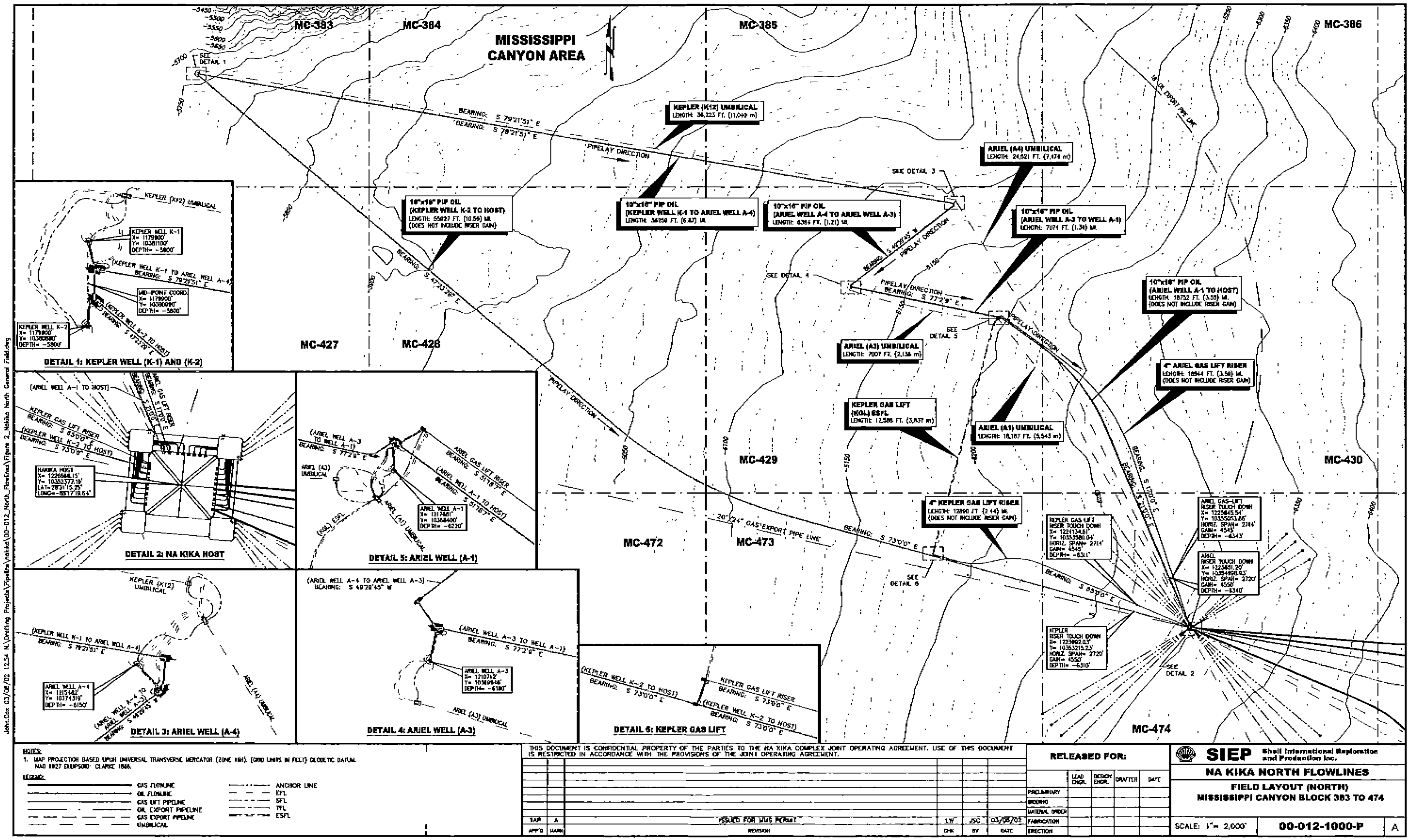

Figure 2. NaKiKa North General Field Arrangement

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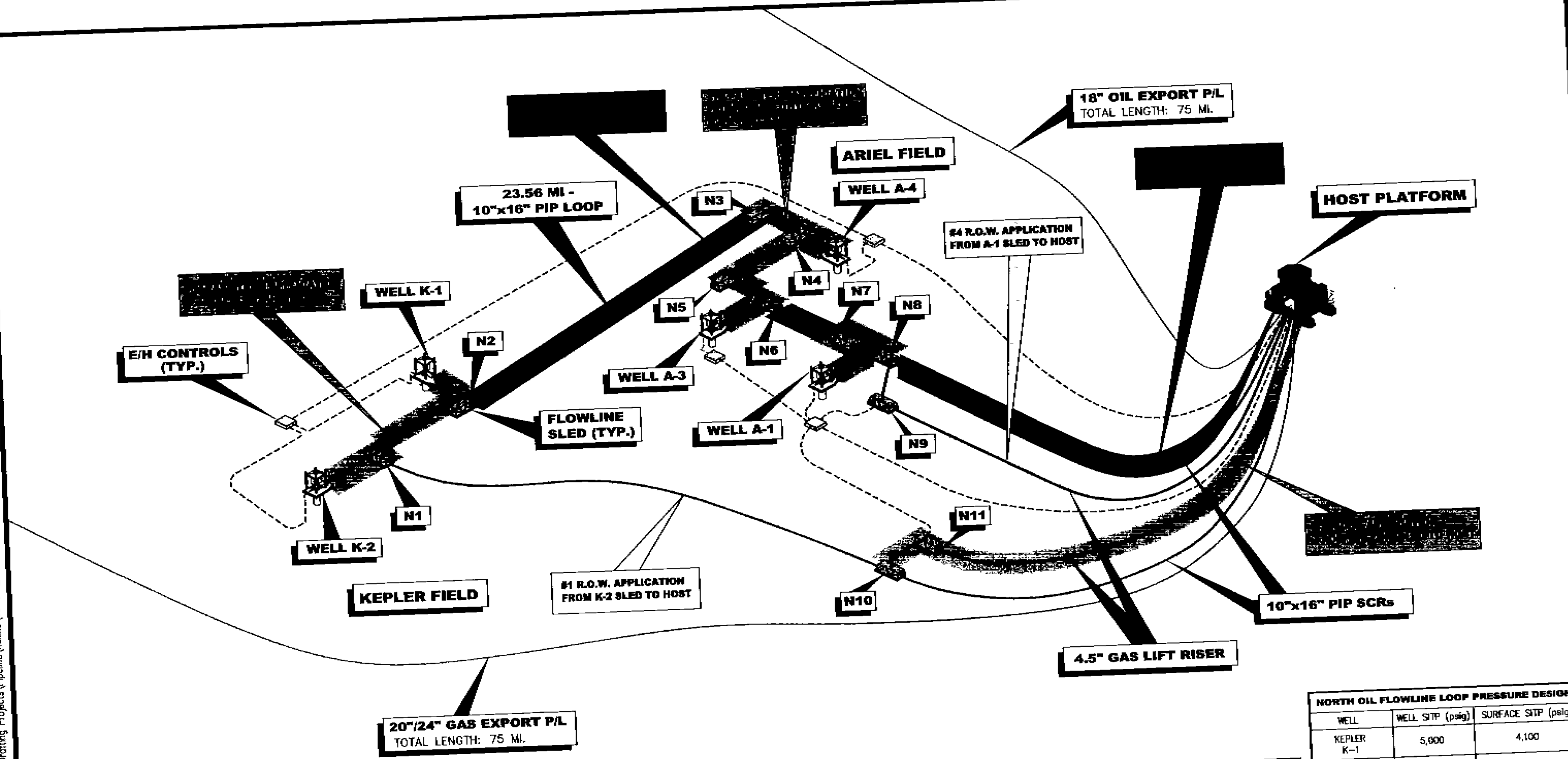
Figure 3. North Oil Flowline and Umbilical "Color Coded" Schematic (Drawing 00-12-1200)



NOTE

1. DESIGN PRESSURE FOR THE ENTIRE LOOP IS BASED ON ARIEL A-4 (GAS) MAXIMUM PRESSURE.

LEGEND

- - - - - - - UMBILICAL
———— OIL
———— GAS

NORTH OIL FLOWLINE LOOP PRESSURE DESIGN		
WELL	WELL SITP (psig)	SURFACE SITP (psig)
KEPLER K-1	5,000	4,100
ARIEL A-1	5,300	3,800
ARIEL A-3	5,600	4,000
ARIEL A-4 (OIL)	5,500	3,900
ARIEL A-4 (GAS)	6,500	5,600

NO.	DATE	REVISION	BY	APP.
A	03/07/02	ISSUED FOR MMS PERMIT APPLICATION	DN	TAP

NAKIKA NORTH FLOWLINES

SIEP Shell International Exploration and Production Inc.

OVERALL FIELD LAYOUT
10"x16" PIP OIL FLOWLINE LOOP
COLOR CODE FOR PERMIT APPLICATIONS

SCALE	NONE	DATE	REF.	REV.
DRAWN	DN	02/02	00-012-1200	A

June.Nguyen 03/19/02 07:55 N:\Drafting Projects\Pipeline\nakika\00-012_North_Flowlines\00-012-1200-A.dwg

Figure 4. "Color Coded" Pipe Segments for North Oil Flowline Loop Permit #5 (Drawing 00-12-1205)

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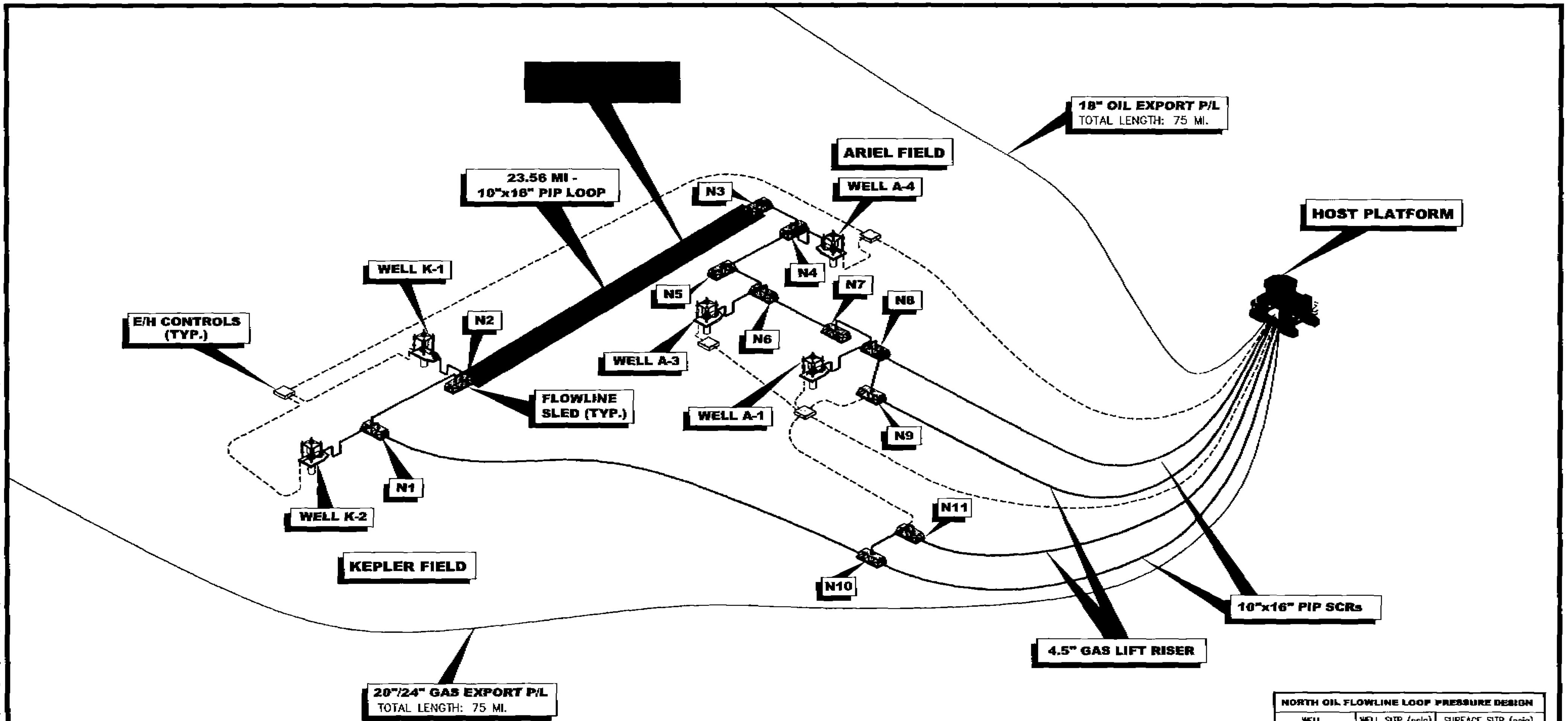


NOTE

1. DESIGN PRESSURE FOR THE ENTIRE LOOP IS BASED ON ARIEL A-4 (GAS) MAXIMUM PRESSURE

LEGEND

- - - - - - - - UMBILICAL
——— OIL
——— GAS

NORTH OIL FLOWLINE LOOP PRESSURE DESIGN

WELL	WELL SITP (psig)	SURFACE SITP (psig)
KEPLER K-1	5,000	4,100
ARIEL A-1	5,300	3,800
ARIEL A-3	5,600	4,000
ARIEL A-4 (OIL)	5,500	3,900
ARIEL A-4 (GAS)	6,500	5,600

NO.	DATE	REVISION	BY	APP.
A	03/07/02	ISSUED FOR MMS PERMIT APPLICATION	DN	TAP

NAKIKA NORTH FLOWLINES

SIEP Shell International Exploration and Production Inc.

10"x16" PIP OIL FLOWLINE LOOP ILLUSTRATION OF PIPE SEGMENT FOR #5 PERMIT APPLICATION

SCALE	NONE	DATE	REF.	REV.
DRAWN	DN	03/02	00-012-1205	A

2. *Permit Applications*

Because of the complexity of the Nakika North Oil flowline loop, individual permit applications are prepared for different flowline segments, jumpers and risers as illustrated in Figure 4 with different colors to indicate different permit applications. Detailed pipe descriptions to be included in each permit application are listed in Table 2. This document is for the pipe segment from the Kepler Well K-1 sled to the Ariel Well A-4 sled, permit application document #5, as highlighted in Table 2 and illustrated in Figure 4. The plat maps for this flowline segment are included in Attachment 1.

Table 2. Permit Application Documents for NaKika North Oil Flowline Loop, 10"x16" PIP System

Permit Number	Pipe Segment Description	Type of Permit
#1	From Kepler Well K-2 Sled N1 to Host: • Midline Sled 5" Pipe: 5.5625" x 0.750", API 5L, X65, Seamless • Midline Sled 10" Carrier Pipe: 10.750" x 0.875", API 5L, X70, Seamless • Flowline PIP - Carrier: 10.750" x 0.812", API 5L, X70, Seamless • Flowline PIP - Casing: 16.000" x 0.750", API 5L, X70, DSAW • Riser PIP - Carrier: 10.750" x 0.875", API 5L, X70, Seamless • Riser PIP - Casing: 16.000" x 0.750", API 5L, X70, DSAW • FPS Hull Piping: 10.750" x 0.875", API 5L, X70, Seamless • Kepler, Static Umbilical System K12 • Kepler Gas Lift, Static Umbilical System KGL	Right of Way
#2	Kepler Gas Lift Riser from Midline Sled N10 to Gas Lift Sled N11 to Host: • Sled 5" Pipe: 5.5625" x 0.750", API 5L, X65, Seamless • Gas Lift Jumper: 5.94" x 0.939", 410, Stainless Steel • Gas Lift Riser Pipe: 4.500" x 0.674", API 5L, X65, Seamless • Stress-Joint Pipe: Tapered from 4.594" x 0.0.761" to 9.352" x 3.14" at the flange • Hull Piping above Flange: 6.625" s 0.875", API 5L, X65, Seamless • Kepler Gas Lift, Static Umbilical System KGL	Right Of Way
#3	From Ariel Well A-3 Sled N6 to A-1 Sled N7 and from N8 to Host: • Sled 5" Pipe: 5.5625" x 0.750", API 5L, X65, Seamless • Sled 10" Carrier Pipe: 10.750" x 0.875", API 5L, X70, Seamless • Flowline PIP - Carrier: 10.750" x 0.812", API 5L, X70, Seamless • Flowline PIP - Casing: 16.000" x 0.750", API 5L, X70, DSAW • Riser PIP - Carrier: 10.750" x 0.875", API 5L, X70, Seamless • Riser PIP - Casing: 16.000" x 0.750", API 5L, X70, DSAW • FPS Hull Piping: 10.750" x 0.875", API 5L, X70, Seamless • Ariel 3, Static Umbilical System A3 • Ariel 1, Static Umbilical System A1	Right of Way
#4	Ariel Gas Lift Riser from A-1 Sled N8 to Gas Lift Sled N9 to Host: • Sled 5" Pipe: 5.5625" x 0.750", API 5L, X65, Seamless • Gas Lift Jumper: 5.94" x 0.939", 410, Stainless Steel • Gas Lift Riser Pipe: 4.500" x 0.674", API 5L, X65, Seamless • Stress-Joint Pipe: Tapered from 4.594" x 0.0.761" to 9.352" x 3.14" at the flange • Hull Piping above Flange: 6.625" s 0.875", API 5L, X65, Seamless • Ariel 1, Static Umbilical System A1	Right Of Way

(Table 2. Continued)

Permit Number	Pipe Segment Description	Type of Permit
#5	From Kepler Well K-1 Sled N2 to Ariel Well A-4 Sled N3: • Sled 5" Pipe: 5.5625" x 0.750", API 5L, X65, Seamless • Sled 10" Carrier Pipe: 10.750" x 0.875", API 5L, X70, Seamless • Flowline PIP - Carrier: 10.750" x 0.812", API 5L, X70, Seamless • Flowline PIP - Casing: 16.000" x 0.750", API 5L, X70, DSAW • Kepler Gas Lift, Static Umbilical System KGL	Right Of Way
#6	Three Kepler Jumpers: • Well K-2 Jumper: 5.94" x 0.939", 410, Stainless Steel • Well K-1 Jumper: 5.94" x 0.939", 410, Stainless Steel • Flowline Jumper from K-2 Sled N1 to K-1 Sled N2: 10.750" x 0.875", API 5L, X70, Seamless • Kepler Gas Lift, Static Umbilical System KGL	Lease Term
#7	From Ariel Well A-4 Sled N4 to A-3 Sled N5 and 6 Jumpers: • Flowline Jumper from N3 to N4: 10.750" x 0.875", API 5L, X70, Seamless • Well A-4 Jumper: 5.94" x 0.939", 410, Stainless Steel • Flowline PIP - Carrier: 10.750" x 0.812", API 5L, X70, Seamless • Flowline PIP - Casing: 16.000" x 0.750", API 5L, X70, DSAW • Flowline Jumper from N5 to N6: 10.750" x 0.875", X70 • Well A-3 Jumper: 5.94" x 0.939", 410, Stainless Steel • Well A-1 Jumper: 5.94" x 0.939", 410, Stainless Steel • Ariel 4, Static Umbilical System A4 • Ariel 3, Static Umbilical System A3	Lease Term

3. *Well and Surface SITP*

The maximum design shut-in tubing pressure (SITP) for the North field, five (5) wells, is 6,500 psig at the wellhead and 5,600 psig at 0 feet MSL of the riser top. This SITP is for well A-4, which will commingle production from the K-1, A-1, A-3 and A-4 zones. The other wells SITPs are less than these maximum values. For information and comparison the individual well SITPs are listed in Table 3. The flowline and riser design temperature is -20°F to 250°F. The produced fluid operating temperature ranges for the flowline and riser are 40°F to 110°F.

The maximum SITP for the gas lift riser at the seabed will be the SITP at the midline sled, which is calculated based on the maximum SITP of 6,500 psig at well A-4 and the maximum SITP of 5,600 psig at 0 feet MSL of the riser top. A linear pressure gradient is used to calculate local SITP along the flowline loop. The maximum SITP at the gas lift riser top is assumed the same as the flowline of 5,600 psig during shut-in condition.

(Table 2. Continued)

Permit Number	Pipe Segment Description	Type of Permit
#5	From Kepler Well K-1 Sled N2 to Ariel Well A-4 Sled N3: • Sled 5" Pipe: 5.5625" x 0.750", API 5L, X65, Seamless • Sled 10" Carrier Pipe: 10.750" x 0.875", API 5L, X70, Seamless • Flowline PIP - Carrier: 10.750" x 0.812", API 5L, X70, Seamless • Flowline PIP - Casing: 16.000" x 0.750", API 5L, X70, DSAW • Kepler Gas Lift, Static Umbilical System KGL	Right Of Way
#6	Three Kepler Jumpers: • Well K-2 Jumper: 5.94" x 0.939", 410, Stainless Steel • Well K-1 Jumper: 5.94" x 0.939", 410, Stainless Steel • Flowline Jumper from K-2 Sled N1 to K-1 Sled N2: 10.750" x 0.875", API 5L, X70, Seamless • Kepler Gas Lift, Static Umbilical System KGL	Lease Term
#7	From Ariel Well A-4 Sled N4 to A-3 Sled N5 and 6 Jumpers: • Flowline Jumper from N3 to N4: 10.750" x 0.875", API 5L, X70, Seamless • Well A-4 Jumper: 5.94" x 0.939", 410, Stainless Steel • Flowline PIP - Carrier: 10.750" x 0.812", API 5L, X70, Seamless • Flowline PIP - Casing: 16.000" x 0.750", API 5L, X70, DSAW • Flowline Jumper from N5 to N6: 10.750" x 0.875", X70 • Well A-3 Jumper: 5.94" x 0.939", 410, Stainless Steel • Well A-1 Jumper: 5.94" x 0.939", 410, Stainless Steel • Ariel 4, Static Umbilical System A4 • Ariel 3, Static Umbilical System A3	Lease Term

3. *Well and Surface SITP*

The maximum design shut-in tubing pressure (SITP) for the North field, five (5) wells, is 6,500 psig at the wellhead and 5,600 psig at 0 feet MSL of the riser top. This SITP is for well A-4, which will commingle production from the K-1, A-1, A-3 and A-4 zones. The other wells SITPs are less than these maximum values. For information and comparison the individual well SITPs are listed in Table 3. The flowline and riser design temperature is -20°F to 250°F. The produced fluid operating temperature ranges for the flowline and riser are 40°F to 110°F.

The maximum SITP for the gas lift riser at the seabed will be the SITP at the midline sled, which is calculated based on the maximum SITP of 6,500 psig at well A-4 and the maximum SITP of 5,600 psig at 0 feet MSL of the riser top. A linear pressure gradient is used to calculate local SITP along the flowline loop. The maximum SITP at the gas lift riser top is assumed the same as the flowline of 5,600 psig during shut-in condition.

Table 3. Calculated Well and Surface SITP

Well	Maximum Well SITP Psig	SITP at 0 ft MSL of Riser Top (psig)	Water Depth at Well Site (feet, MSL)	Comments and Notes
Kepler1 (K-1) Oil	5,000	4,100	-5,800	Maximum values at the seafloor/top of riser produced on its own
Kepler 2 (K-2) Oil	N/A	N/A	-5,800	Not available
Ariel 1 (A-1) Oil	5,300	3,800	-6,250	Maximum values at the seafloor/top of riser. Assumes A-1 produced on its own
Ariel 3 (A-3) Oil	5,600	4,000	-6,150	Maximum values at the seafloor/top of riser. Assumes A-3 produced on its own
Ariel 4 (A-4) Oil*	5,500	3,900	-6,150	Maximum values at the seafloor/top of riser. Assumes A-4 Oil produced on its own.
Ariel 4 (A-4) Gas*	6,500	5,600	-6,150	Maximum values at the seafloor/top of riser. Assumes A-4 gas produced on its own.

Note: *It is uncertain whether Ariel Well A-4 is gas or oil well. The maximum SITP of a gas well is used for pipeline design.

4. *Flowline Design Approach*

The pipe design pressure and subsequent pipe wall thickness requirements are based on the design equation as required in 30CFR250 Subpart J. All the flowline segments of the North loop are designed based on the maximum SITP at Ariel gas wellhead of 6,500 psig. The maximum SITP of 5,600 psig at 0 feet MSL of the riser top is used. The gas lift riser design pressure is based on the local SITP at the midline sled in the flowline. In addition and when applicable, the effects of external pressure in the design are considered. These design calculations and related considerations are presented in Section II of this permit application document.

5. *Flowline Jumper and Well Jumper Design*

In addition to the flowlines, design considerations of the short sections of pipe connecting flowline "sled" to flowline "sled" (flowline jumper) and wellhead to flowline "sled" (well jumpers) are presented in those permits where jumpers are considered (see Table 2).

II. FLOWLINE DESIGN

The NaKika North Flowline Loop system is designed to transport produced well fluids from the five wells in the NaKika north field located Mississippi Canyon Block 383 (MC-383), MC-429 to NaKika host located in Mississippi Canyon Block 474 (MC-474) as illustrated in Figure.1. The flowline pressure piping is designed to contain the maximum full well A4 pressure of 6,500 psig. The flowlines are a pipe-in-pipe (PIP) system and thermally insulated to ensure normal operation above the hydrate formation temperature of the commodity and, in addition, to maintain temperatures above the hydrate formation temperature for the longest practical time during flow interruptions. In addition, the flowlines are electrically heated as a remediation tool that can be used to mitigate hydrate problems. The flowline is piggable with a scraper launcher and receiver located on the NaKika Host platform (FPS).

The NaKika North flowlines traverse elevations from –6,340 feet MSL to +67 feet MSL for a total elevation change of 6,407 feet. The design includes consideration of both elevation changes and internal fluid hydrostatics (i.e. density, etc.). Each of the flowline risers are terminated with pipe-in-pipe Steel Catenary Riser Flex Joints with a maximum operation pressure (MAOP) of 5,600 psig at –70 feet MSL elevation.

For the PIP segments of the system, external pressure is 0 psig for the carrier pipe. For other items that compose the system, such as the sled piping and jumpers that are not PIP, the localized external pressure is considered as part of the design. For clarity and consistency all pressure calculations illustrated herein utilize *Gauge pressure (psig)*. External hydrostatic pressure is consistently applied throughout the calculations.

Glossary of Main Terms:

- **Carrier pipe** The pressure containing inside pipe of the insulated pipe-in-pipe system.
- **Casing pipe** The water exclusion outside pipe of the insulated pipe-in-pipe system.
- **psig** Gauge pressure, pounds-per-square-inch at sea level conditions.
- **MSL** Mean Sea Level Elevation Datum
- **VIV** Vortex Induced Vibration
- **SITP** Shut-in Tubing Pressure
- **PIP** Pipe-In-Pipe
- **MAOP** Maximum Allowable Operating Pressure
- **FBE** Fusion Bonded Epoxy
- **TLPE** Triple Layer Polyethylene
- **SCR** Steel Catenary Riser

1. *Commodity To Be Transported*

Available reservoir fluid compositions for the Ariel reservoirs are summarized in Table 4. These compositions are based on bottomhole fluid samples collected from the Ariel Wells A-1 and A-2. The assumptions for the Kepler field used in the design are presented in Table 5.

Table 4. NaKika North Oil Field Ariel Produced Fluid Composition

Contents	Ariel #1 (Well A-1)	Ariel #4 (Well A-4)
Water Depth (ft.)	6,250 ft	6,150 ft
Expected Hydrocarbon	Oil	Oil or Gas
API Gravity (degree API @ 60 °F)	28	28
Gas SG Relative to Air	.63	.63
Early Life GOR- (scf/bbl)	1,000	1,000
Late Life GOR- (scf/bbl)	3,000	3,000
Bubble/Dew Point – (psi)	7,116-7,360	7,116-7,360
H2S – (%)	nil	nil
CO_2 – (mol %)	0.1	0.1
Sand Production	nil	nil
Life – (years max)	20	20
Artificial Lift	Gas lift riser	Gas lift riser

Table 5. NaKika North Oil Field Kepler Produced Fluid Composition

Description	Kepler #2 (Well K-1)	Kepler #3 (Well K-2)
Water Depth (ft.)	5,800 ft	5,800 ft
Expected Hydrocarbon	Oil	Oil
API Gravity (degree API @ 60 °F)	28	28
Gas SG relative to air	0.7	0.7
Early Life GOR- (scf/bbl)	950	950
Late Life GOR- (scf/bbl)	1,400	1,400
Bubble/Dew Point – (psi)	5,400	5,400
H2S – (%)	nil	nil
CO_2 – (mol %)	0.1	0.1
Sand production	nil	nil
Life – (years max)	20	20
Artificial Lift	Gas lift riser	Gas lift riser

2. *Pipe-In-Pipe (P-I-P) Flowline Segment, Riser Specifications and Weight*

The NaKika North Flowline Loop is formed by five 16" x 10" PIP flowline segments connecting the five wells. As listed in Table 2, the pipe segments considered in the permit application are from the K-1 first end sled (N2) to the A-4 second end sled (N3). The total length of this pipe segment is 36,259 feet. The properties of the each PIP section are listed in Table 6.

The Specific Gravity is calculated as:

Weight in Air (empty) / Water Displacement in Sea Water

Seawater specific weight of 64 lb/ft^3 is used.

Table 6. Pipe Properties for Flowline Segment from K-1 to A-4

Parameter	5" Sled Pipe	10" Sled Pipe	Flowline
Length (feet)	~15	~20	36,259
Pipe System	Single pipe	Single pipe	PIP
Carrier Pipe: OD x WT, Grade	5.5625"x0.750", X65, Seamless	10.750"x0.875", X70, Seamless	10.750"x0.812", X70, Seamless
Casing Pipe: OD x WT, Grade	N/A	N/A	16.000"x0.750", X70, DSAW
Pipe Specification	API-5L	API-5L	API-5L
External Coating (mil)	Painted	FBE 8-10	FBE Casing 16-18 Carrier 8-10
Internal Coating (mil)	N/A	N/A	Copon 2306 WB On Casing Pipe Only 2-3
Insulation Material[1]	C-Therm FPP	C-Therm FPP	PUF & PEJ
Min. Insulation Thickness (in)	3	3	1.535 PUF & 0.080 PEJ
Empty Weight in Air, lb/ft	62.98	131.55	212.54
Water Displacement, lb/ft	46.96	98.17	89.76
Empty Weight in Water, lb/ft	18.84	37.67	122.78
SG (empty, seawater=1)	1.40	1.38	2.37
Product Filled Weight in Air[2], lb/ft	68.08	156.60	238.29
Product Filled Weight in Water[2], lb/ft	23.94	62.72	148.53
Product Filled SG[2]	1.51	1.64	2.66
Hoop Stress Factor	0.72	0.72	0.72

Notes:

1. PUF = Polyurethane Foam, density of 4 lb/ft^3
   PEJ= Polyethylene Jacket, density of 56 lb/ft^3
   C-Therm FPP = Cummings C-Therm Pour-In-Place, density of 43 lb/ft^3 dry and 48 lb/ft^3 wet
2. Based on crude oil density of 56.7 lb/ft^3.

3. *Cathodic Protection*

Pipe-In-Pipe Casing Pipe (Flowline and Riser):

Type of CP:	Sacrificial anode
Anode Material:	Aluminum, Zinc & Indium Alloy
Spacing:	316 – 324 feet *
Anode weight:	128 lb. Minimum Alloy Weight

$W_0 := 128 \cdot lb$ _ *Weight of the Anode*

$D := 16 \cdot in$ _ *Pipe Outside Diameter*

$I := 324 \cdot ft$ _ *Separation between Anodes*

$R := 8.4 \cdot \frac{lb}{amp \cdot yr}$ _ *Rate of Consuming, lb/year*

$C := 3.82 \cdot 10^4 \cdot in \cdot \frac{ft}{amp}$

$L_e := \frac{W_0 \cdot C}{D \cdot I \cdot R}$ _ *Anode Life per MMS Letter, Ref. No. MS 5232*

$L_e = 112yr$

Anode life: 112 years

* Note: 324 feet spacing was used for the calculations to be conservative.

Pipe-In-Pipe Carrier Pipe (Flowline and Riser):
In the as-designed configuration, the exterior of the carrier pipe is part of a dry, sealed annulus with no corrosion potential. Should the outer casing be breached such that water does enter the annulus, corrosion rates within the water-flooded annulus are negligible as oxygen is quickly depleted.

4. *External Protective Coatings*

Pipe-In-Pipe Casing Pipe, Flowline:
External Corrosion Coating: Fusion Bonded Epoxy (FBE), 16 mils minimum and 18 mils nominal

Pipe-in-Pipe Carrier Pipe, Flowline:
External Corrosion Coating: FBE, 8 mils minimum and 10 mils nominal
Insulation Coating: Inner Layer – Polyurethane Foam, 4 lb/ft^3, 1.535" minimum
Outer Layer – Solid Polyethylene Jacket, 0.08" minimum

5. *Internal Coating and Corrosion Control*

The flowline and riser carrier pipe is internally blasted to remove mill scale from the pipe. The flowline and riser carrier pipes are not internally coated.

The flowline and riser casing pipe is internally blasted and coated with 2mils minimum /3mils nominal of COPON EP 2306 WB internal coating. This coating serves three purposes

- reduces mill scale to help offshore welding operations,
- provides scaling surface for water stops,
- and reduces mill scale build up at water stops to provide a better electrical isolation between casing and carrier pipe.

Separate umbilical tubes convey corrosion inhibitor to each subsea tree. At each tree the flowing stream is injected with corrosion inhibitor.

6. *Water Depth and Elevations*

The water depths along the North Oil Loop at critical locations are listed in Table 7 with the pertinent information to this document highlighted. The maximum and minimum water depths are as follows:

Maximum Water Depth:	-6,350 ft MSL near Riser Touchdown in MC-474, NaKika Host.
Minimum Water Depth:	-5,800 ft MSL in MC-383 at Kepler Wells
Maximum Elevation:	+67 ft MSL in MC-474 at the Host termination flange

Table 7. North Oil Loop, Water Depth at Critical Locations

	Location	Water Depth (ft)
Kepler Well K-1 Sled (N2)	MC-383	-5,800
Kepler Well K-2 Sled (N1)	MC-429	-5,800
Ariel Well A-1 Sleds (N8 and N7)	MC-429	-6,250
Ariel Well A-3 Sleds (N6 and N5)	MC-429	-6,150
Ariel Well A-4 Sled (N3, N4)	MC-429	-6,150
Midline Sled (N10)	MC-473	-6,225
Flowline to SCR Transition for K-2 to Host	MC-474	-6,290
SCR Touchdown for K-2 to Host	MC-474	-6,310
Flowline to SCR Transition for A-1 to Host	MC-474	-6,300
SCR Touchdown for A-1 to Host	MC-474	-6,340
Riser Flex-Joint	MC-474	-70
Host SCR Termination	MC-474	+67

7. *Design Capacity of Flowlines*

The North flowline loop is designed for a maximum flow-rate of 50,000 BFPD/100 MMSCFD.

8. *Source Pressures and Temperatures*

The pressure design calculations for the entire North Oil Loop are based on the maximum SITP at Ariel well A-4 and the calculated SITP at 0 feet MSL of the riser top. Local SITP is based on the change in pressure due to the difference in elevation.

Maximum SITP at A-4: 6,500 psig
Maximum SITP at 0 feet MSL of the riser top: 5,600 psig

Flowline operating temperature is 40 °F to 110 °F

The subsea tree is equipped with three pressure barriers in the form of hydraulically actuated fail-close valves. These are the Production Master Valve (PMV), the Production Wing Valve (PWV) and the Production Shut Down Valve (PSDV) as shown in the attached Safety Schematic and Flowline Diagram Drawings 00-012-3002 (Attachment 2). In addition, ROV operable isolation valves are located on the flowline sleds and at each well.

When flowing the wells, pressure is managed using remotely controlled subsea chokes located on the subsea trees. Pressure sensors are positioned on the subsea tree to facilitate control of the subsea production system.

9. *Downstream Facilities and Design Pressure*

Topside sensors monitor flowline arrival pressure. Each flowline is fitted with a remotely actuated fail-close shutdown valve (SDV) as shown on the Safety Schematic and Flowline Diagram (see Attachment 2, drawing 00-012-3002). There are dual, redundant SDV and pressure sensors that control each SDV. In addition, a control valve is used to control flow rate and pressure. Each SDV is a API 6A 10,000 psig working pressure power actuated, fail –close type valve. Each SDV is designed to safely contain the source pressure produced by the wells. The SDVs are controlled from the platform Master Control System (MCS) and remain open only so long as system data indicates safe a operation mode. There are PSL and PSH sensors just upstream of the platform flowline SDV. Under normal operating conditions, the arriving pressure is controlled by the subsea chokes such that it is approximately 200 - 225 psig as the produced fluid flows into the platform inlet separator.

Additional details concerning the downstream facilities design are contained in the Na Kika Host expansion Permit application previously submitted to the MMS.

10. *Pipe Collapse Design*

The casing pipe is subjected to external hydrostatic pressure at depth and has been designed to resist collapse. Flowline jumpers, well jumpers and sled piping as well as sled pipe spools are exposed to sea water and are subjected to external hydrostatic pressure. Theses pipe segments are also checked against collapse

For the pipe segment considered in this document, the most highly loaded point is at Well A-4 sled N3 of -6,340 feet MSL. The calculations are performed for critical location along this pipe segment where either the pipe property changes or the water depth is the maximum. The calculated safety factors against collapse are summarized in Table 8. Detailed calculations are presented in Attachment 3, Calculations 1, 2, and 3. All the calculations are performed by using MathCAD, a commercial math calculation software.

Table 8. Safety Factors Against Pipe Collapse

Calculation	Pipe Description	Water Depth (feet)	Collapse Pressure (psig)	Collapse Safety Factors
1	Sled, 5" Pipe: 5.5625" x0.750", API 5L, X65, Seamless	-5,800	17,419	6.37
2	Sled, 10" Pipe: 10.750"x0.875", API 5L, X70, Seamless	-5,800	10,817	3.96
3	Flowline Casing Pipe: 16.000"x0.750", API 5L, X70, DSAW	-6,150	4,643	1.70

11. *Pipe Internal Design Pressure and MAOP Calculations*

As the planned flowline facility is in deepwater, external pressure is included in the pipe stress calculations for those parts of the system that are exposed to seawater. This is in accordance **ASME B31.8 Gas Transmission and Distribution Piping Systems**, ***A842.221 Hoop Stress.***

For consistency the same calculation format is used for each segment. For pipe-in-pipe carrier pipes and pipes above sea level, the external pressure equals zero. The pipe internal design pressure calculated is identical to pressure calculated using the notation of Paragraph ***250.152 of 30 CFR 250 Subpart J.***

A linear pressure gradient along the loop based on the maximum SITP at the wellhead (Ariel-4) and the 0 feet MSL of the riser top is used to calculate the local SITP. The pressure calculations are performed for the critical points or locations where either the pipe and/or the environmental properties change along the pipeline loop. Calculations are performed for the cases listed in Table 9 with the results summarized in the next section and details in Attachment 3.

Table 9. Calculation Cases for Carrier Pipe Internal Pressure Design

Calculation	Carrier Pipe Segments	Pipe Description	Water Depth (feet)	Exposed to Seawater	Design Factor
4	Sled N2, 5" Sled Pipe	5.5625" x 0.750", API 5L, X65, Seamless	-5,800	Yes	0.72
5	Sled N2, 10" Sled Pipe	10.750" x 0.875", API 5L, X70, Seamless	-5,800	Yes	0.72
6	Flowline at N2	10.750" x 0.812", API 5L, X70, Seamless	-5,800	No	0.72
	Flowline at N3	10.750" x 0.812", API 5L, X70, Seamless	-6,150	No	0.72
7	Sled N3, 5" Sled Pipe	5.5625" x 0.750", API 5L, X65, Seamless	-6,150	Yes	0.72
8	Sled N3, 10" Sled Pipe	10.750" x 0.875", API 5L, X70, Seamless	-6,150	Yes	0.72

Term Definitions in the Calculations

Local SITP

The Local SITP along the flowline system is calculated based on the maximum SITP at wellhead and at the top of riser assuming the well with the maximum SITP is producing by itself. A column of fluid extending from the wellhead to the top of the riser on the Nakika Host Platform results in a linear pressure gradient along the flowline and riser length. This pressure gradient is used to calculate the "local" shut-in pressure at all points along the flowline segment.

Design Pressure

The Design Pressure is calculated based on the "Thin" wall pressure design formula in accordance with ASME B31.8 Gas transmission and Distribution piping Systems, *A842.221 Hoop Stress* and paragraph *250.1002 of 30 CFR 250 Subpart J.* As the planned flowline facility is in deepwater, external pressure is included in the pipe stress calculations for those parts of the system that are exposed to seawater. For consistency the same calculation format is used for each location along the segment.

"Internal" Hydrotest Pressure

The internal hydrotest pressure is calculated based on 1.25 × the Top of Riser Shut-in Pressure as well as the hydrotest fluid gradient. If the hydrotest is performed onshore, there will be no hydrotest fluid gradient. This pressure is the pressure that would be "read" on a gauge placed at that particular location.

"Effective" Hydrotest Pressure

The "effective" hydrotest pressure is the net pressure the pipe experiences, which is calculated by subtracting the external pressure from the internal test pressure at the calculation location. If the hydrotest is performed onshore, there will be no "external" pressure.

Hoop Stress during Hydrotest

The hoop stress due to the net pressure the pipe experiences should not exceed 95% of SMYS of the pipe during hydrotest. For items tested onshore and offshore, there will be two (2) associated calculations.

Required Hydrotest Pressure Check

The "required" hydrotest pressure at any location is required to be 1.25 times the "local" shut-in pressure subtracting the hydrostatic pressure where appropriate at that location. Thus, using the "local" shut-in pressure at each location as a basis, the "effective" hydrotest pressure is confirmed to be larger than the "required" hydrotest pressure.

MAOP Determination

The Maximum Allowable Operating Pressure (MAOP) at a particular location along the flowline segment is determined by the lowest of the following:

- 80% the Hydrotest Pressure
- Pipe Design Pressure
- Design Pressure for Flanges, Valves, Fittings and/or other components which are present at the calculation location

If a particular location in the flowline (i.e. flowline sled) is hydrotested multiple times (i.e. onshore and offshore), the test resulting in the "highest" minimum hydrotest pressure will dictate the MAOP.

Summary of Internal Pressure Design Calculations

The allowable hoop stress is 72% of SMYS for flowline design, 60% of SMYS for riser design and 95% of SMYS during hydrotest. The calculated results are summarized in Table 10 and depicted in Figure 6. Detailed calculations are presented in Attachment 4. In summary the flowline segment from the N2 sled to the N3 sled has a MAOP of 7,614 psig.

Table 10. Summary of Pressure Design Calculation

Item	Description	Location	Water Depth	External Pressure	Design Pressure	"Effective" Hydrotest Pressure(1)	Standard Hydrotest Pressure MAOP(2)	Design Pressure for Fittings at Water Depth(3)	MAOP(4)	"Local" Shut-in Pressure(5)	Hoop Stress during Hydrotest
			fsw	psig	psig	psig	psig	psig	psig	psig	%SMYS
1	5.5625" x 0.750", X65	5" N2 Sled Piping	-5,800	2,578	15,198	7,018	8,192	9,228	8,192	6,449	41.2%
2	10.750"x0.875", X70	10" N2 Sled Pipe Spool	-5,800	2,578	10,782	7,018	8,192	9,228	8,192	6,449	63.3%
3	10.750"x0.812", X70	Flowline at Well K-1 Sled N2	-5,800	0	7,614	9,595	7,676	9,228	7,614	6,449	92.6%
4	10.750"x0.812", X70	Flowline at Well A-4 Sled N3	-6,150	0	7,614	9,751	7,801	9,383	7,614	6,500	94.1%
5	10.750"x0.875", X70	10" N3 Sled Pipe Spool	-6,150	2,733	10,938	7,018	8,347	9,383	8,347	6,500	63.3%
6	5.5625" x 0.750", X65	5" N3 Sled Piping	-6,150	2,733	15,354	7,018	8,347	9,383	8,347	6,500	41.2%
								Minimum	7,614		
								Maximum	8,347		

1) The "Effective" Hydrotest Pressure is the net pressure the pipe experiences during hydrotest, such as:

"Effective" Hydrotest Pressure = (1.25 x SITP @ Top of Riser) + Pfluid (Internal Fluid Presure) - Pstatic (External Pressure of Sea Water, if exposed to seawater)

2) Standard Hydrotest Pressure MAOP (Standard MAOP) is 80% of the "Effective" Hydrotest Pressure + External Pressure of Sea Water.

3) Design pressure for fittings or valves + external pressure at the fittings or valves.

4) MAOP is the least of internal design pressure, standard MAOP and minimum design pressure of fittings, flanges and valves where applicable.

5) Pressure profile is based on the maximum SITP at the wellhead and at 0 fecet MSL of the riser top given in Design Basis Document. A linear pressure gradient is used.

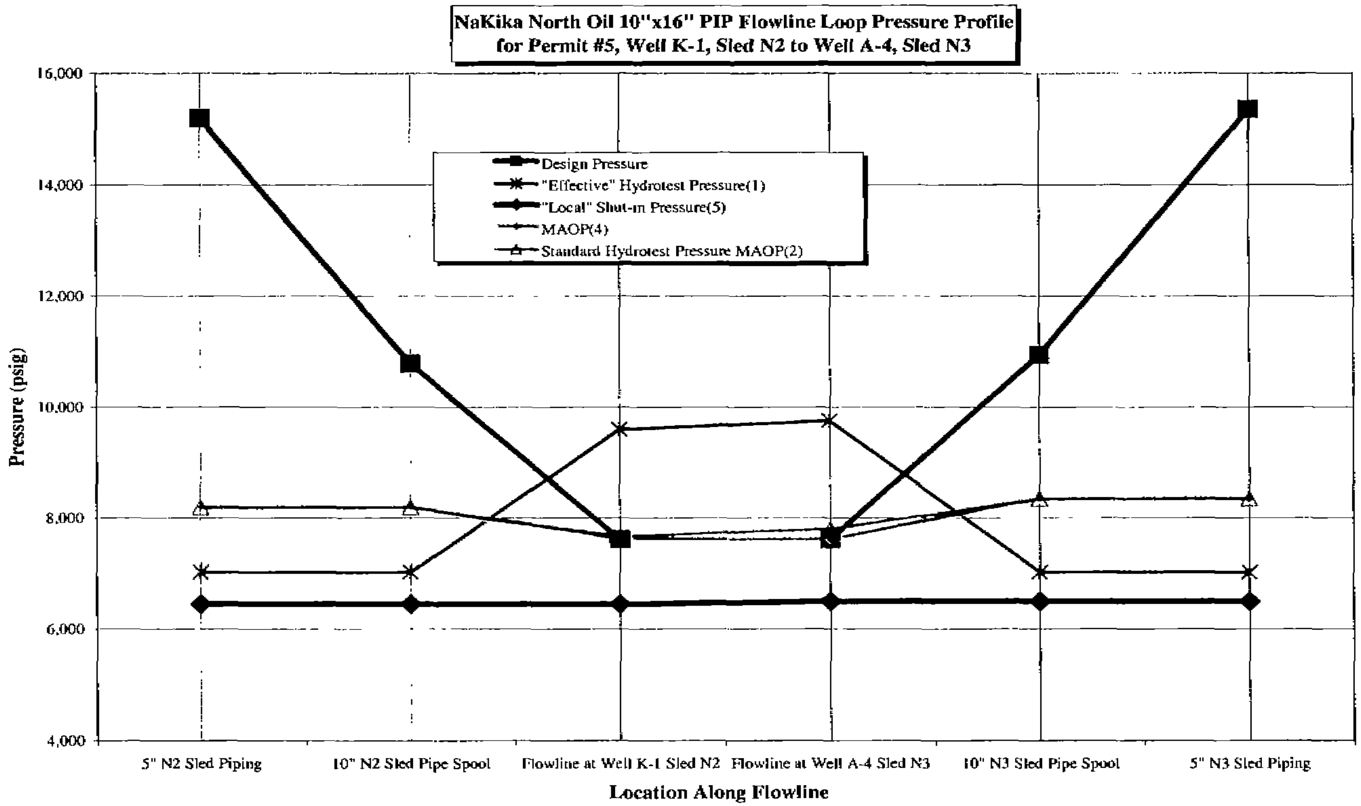


Figure 5. Pressure Design Profile

12. *Pressure of Flanges, Fittings, and Valves*

Flanges:
API 6A 10,000 psig operating pressure.
MAOP = 10,000 psig

5" Manual Gate Valves (on sleds):
API 6A 10,000 psig operating, fabricated from material conforming to temperature classification "P"
MAOP = 10,000 psig

10" Gate Actuated Valves On Initiation Sleds Except Gas Lift Sleds:
API 6A 6,650 psig operating fabricated from material conforming to temperature classification "P"
MAOP = 6,650 psig

Fittings:
Forged Steel Fittings to comply with MSS SP75 "Specification for High test Wrought Butt Weld Fittings", forged material is ASTM A694 F-70. Designed to conform to ASME pressure vessel code, Section VIII, division 1, 2 and 3. Burst Pressure and Design Working Pressure are equal to or greater than the adjoining pipe.

13. *Hydrostatic Test Pressure and Duration*

After installation is completed, the riser, flowline, and startup sled will be tested together from a pig trapper located on the NaKika Host, i.e., the piping between the riser termination flex-joint and pig trappers on the platform will be tested. The flowline and well jumpers are fabricated onshore after pipeline installation in order to get a more precise fit between the respective connecting points on the subsea sleds. As noted previously, these jumpers will be hydrostatically tested onshore after fabrication and just prior to installation. Once all jumpers are installed, a nominal "stand-up" pressure test will be performed in order to test the mechanical connectors' seal and integrity.

Test pressure has been calculated to be no less than 125% of maximum possible pressure at all points in the flowline system. The required Maximum Allowable Operating Pressure (MAOP) at the wellhead of Ariel 4 is 6,500 psig. The required MOP at the TLP (+67 ft MSL) end of the flowline is 5,590 psig. The test pressure and duration can be summarized in the following table.

Table 11. Hydrostatic Test Pressure Summary

Test Medium:	Seawater
Test gauge elevation	+67 ft MSL
Minimum Pressure:	= 6,988 psig (125% of MAOP at top)
Maximum Pressure:	= 7,188 psig (200 psig allowance)
Duration:	8 hours minimum

14. *Electrical Heating*

To enable single flowline flow assurance methods, an electrically heated pipe-in-pipe flowline will be used. A/C power will be applied directly to the ten-inch carrier pipe. This power is applied at the middle of each flowline segment via a mid-line connector. The mid-line connectors are ASTM A-694 steel forgings welded in-line with the flowline pipe. The connectors were analyzed employing ASME Section VII Div. 2 acceptance criteria. The pipe's electrical resistance (more accurately known as the "skin effect") directly heats the inner pipe. The outer pipe remains grounded to subsea sleds on either side of he connector and the seawater. Voltage drops across the inner pipe until it grounds at the subsea sled ends. Non-metallic bulkheads will be used to electrically insulate the inner pipe from the outer pipe and to prevent flooding of the entire annular area in the case of a casing pipe breech.

15. *Volume of Worst Case Hydrocarbon Release*

The maximum potential release of hydrocarbon is estimated in accordance with 30CFR250, Section 254.47. The release estimate is based on the following:

- Complete failure of the flowline at or near the well site and at the base of the riser.
- Initial well expected flowrate.

Release detection time:	300 seconds
Time to close platform-boarding valve:	60 seconds
Time to close well Production Shut-Down Valve:	300 seconds
Total Time:	660 seconds = 0.00764 days

For a line failure at the base of the A-4 sled location, the maximum release is the total response time shown above multiplied by the maximum expected flowrate of 50,000 BOPD. In addition, it is assumed that since the flowline is upward sloping from the failure location that all the line fill volume would not be released since it would be contained by hydrostatic pressure. Therefore, the maximum release is 382 barrels

For a line failure near the K-1 well, the maximum release is the total response time shown above multiplied by the maximum expected flowrate of 50,000 BOPD (382 barrels). Since the flowline is downward sloping from the failure location, it is expected that all the line fill volume of 2,930 bbls (line length of approximately 36,223 feet with a volume of 0.0809 bbl/ft) would be released since it would not be contained by hydrostatic pressure. Therefore, the maximum release is: 3,312 barrels (2930 bbls + 382 bbls).

It should be noted that this is certainly a worst case scenario since it is based on early field life flowrates/pressures will decline over time. In addition, the event of water displacing the entire flowline of product is conservative due to the changes in elevation and hydrostatic head.

16. *Umbilical Design Information*

General Information

In addition to the flowlines, five steel tube umbilicals will service the Nakika North fields. The A1 and A4 dynamic umbilicals will be routed through separate pull tubes (I-tubes) at the Nakika Host platform, which will offer protection from mechanical and environmental forces. A bend stiffener at the base of each I-tube will reduce umbilical movements and limit fatigue. The static A3, K12 and KGL umbilicals shall extend from the A1 and A4 subsea terminations to the A3 cluster, Kepler cluster and Kepler Gas Lift Sled respectively.

The umbilical systems for NaKika North field are listed below. One permit flowline segment may employ several umbilical systems. The umbilical systems pertaining to the Permit #5 pipe segments K-1 sled to A-4 sled are highlighted. Plat maps for the Kepler (K12) umbilical system are included in Attachment 1 of the NaKika North Oil Flowline Permit #1. Plat maps for the rest of the umbilicals are also included in Attachment 1 of the NaKika North Oil Flowline Permit #1.

Ariel 1, Static/Dynamic Umbilical System (A1)

- 5 off 1 1/4" OD SeaCAT tubes, layed-up in a central bundle around a center filler.
- 8 off 5/8" OD 19-D tubes
- 4 off 6mm^2 electrical quad cables
- 7 off filler elements on the outer pass

Ariel 4, Static/Dynamic Umbilical System (A4)

- 6 off 1 1/4" OD SeaCAT tubes, layed-up in a central bundle around a center filler
- 9 off 5/8" OD 19-D tubes
- 3 off 6mm^2 electrical quad cables
- 9 off filler elements on the outer pass

Ariel 3, Static Umbilical System (A3)

- 4 off 1 1/4" OD SeaCat tubes, layed-up with 4 fillers in a central bundle around a center filler
- 7 off 5/8" OD 19-D tubes
- 2 off 6mm^2 electrical quad cables
- 8 off filler elements on the outer pass

Kepler, Static Umbilical System (K12)

- 5 off 1 1/4" OD SeaCAT tubes layed-up in a central bundle around a center filler
- 8 off 5/8" OD 19-D tubes
- 3 off 6mm^2 electrical quad cables
- 8 off filler elements on the outer pass

Kepler Gas Lift, Static Umbilical System (KGL)

- 2 off 1 1/4" OD SeaCAT tubes
- 2 off 5/8" OD 19-D tubes
- 2 off 6mm^2 electrical quad cables

The umbilical system tubes, fittings, and connectors will be designed for a maximum operating pressure of 10,000 psi.

Table 12. Summary Umbilical Information:

Cross Section Design Description	Static Section	Dynamic Section
A1 Outside Diameter	5.3 in.	5.5 in.
A1 Weight in air (full)	20.18 lb/ft	21.29 lb/ft
A1 Submerged Weight (full)	13.34 lb/ft	13.02 lb/ft
A4 Outside Diameter	5.7 in.	5.9 in.
A4 Weight in air (full)	23.40 lb/ft	24.63 lb/ft
A4 Submerged Weight (full)	15.33 lb/ft	14.86 lb/ft
A3 Outside Diameter	5.0 in.	NA
A3 Weight in air (full)	16.78 lb/ft	NA
A3 Submerged Weight (full)	10.72 lb/ft	NA
K12 Outside Diameter	5.3 in.	NA
K12 Weight in air (full)	19.95 lb/ft	NA
K12 Submerged Weight (full)	13.14 lb/ft	NA
KGL Outside Diameter	4.3 in.	NA
KGL Weight in air (full)	9.84 lb/ft	NA
KGL Submerged Weight (full)	4.71 lb/ft	NA

III. INSTALLATION REQUIREMENTS

No trenching is required, as the water depths along the flowline and umbilical routes are greater than 200 ft.

IV. PIPELINE CROSSINGS

There are no pipeline crossings along the route.

V. CONSTRUCTION INFORMATION

- Installation Plans and Construction Method
  Refer to Table 1.

- Project Engineer
  Flowline: Tom Preli (281) 544 4097
  Umbilicals: Katrina Paton (281) 544 2837

VI. ATTACHMENTS

ATTACHMENT 1
Flowline Plat Maps for NaKika North Flowline Permit #5

ATTACHMENT 2
Safety Schematic and Flowline Diagram for NaKika North Flowline Loop

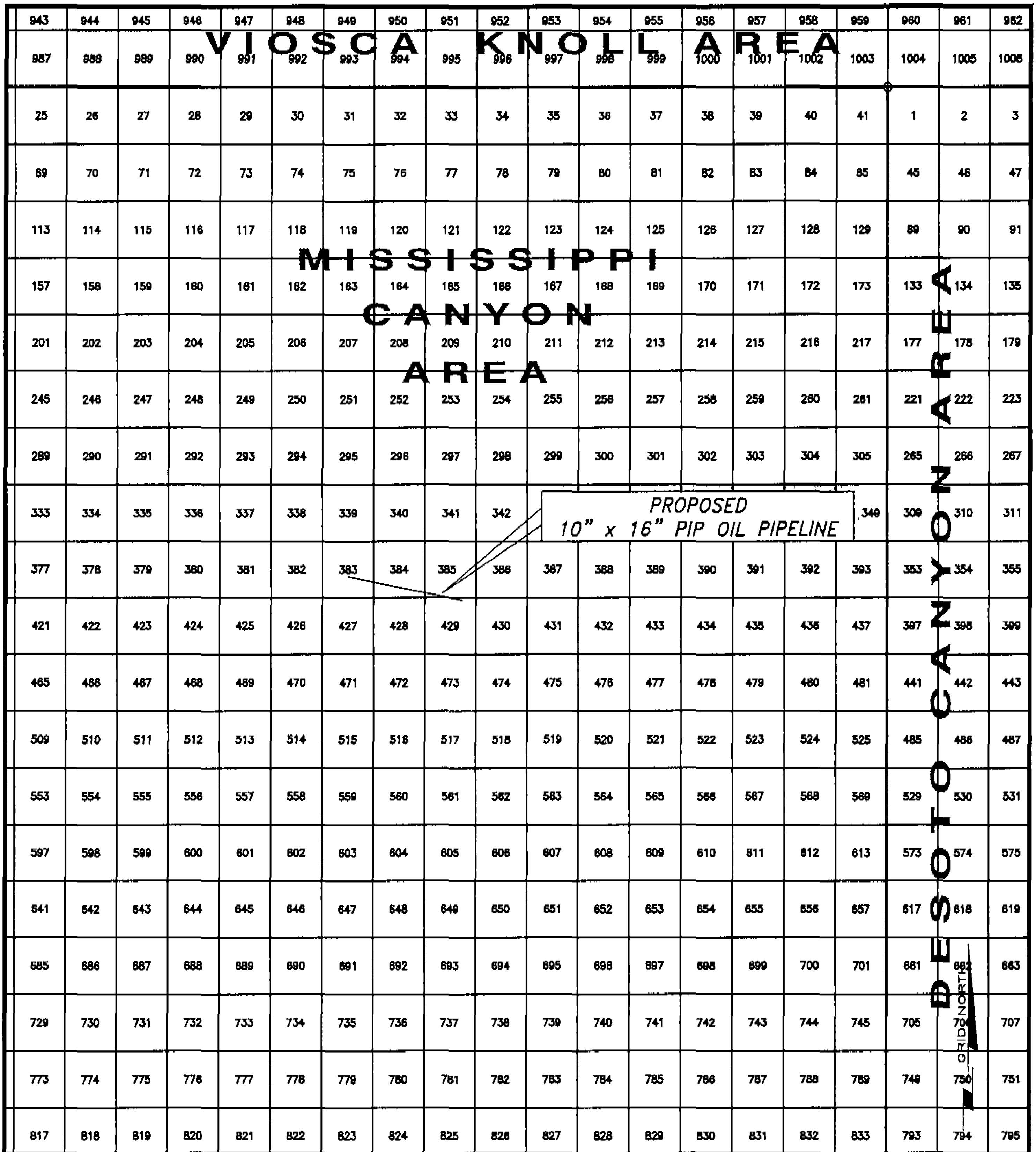
ATTACHMENT 3
Detailed Calculations for Pipe Collapse Design

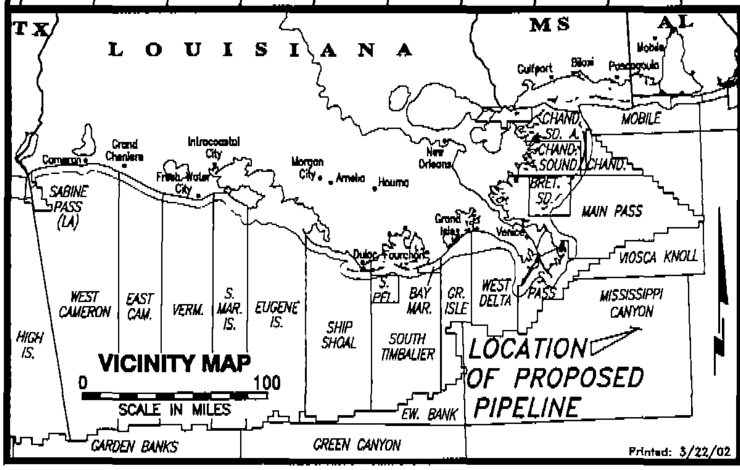
ATTACHMENT 4
Detailed Calculations for Pipe Internal Pressure Design

ATTACHMENT 1

Flowline Plat Maps for NaKika North Flowline Permit #5

BEST AVAILABLE COPY





SHELL OFFSHORE INC.

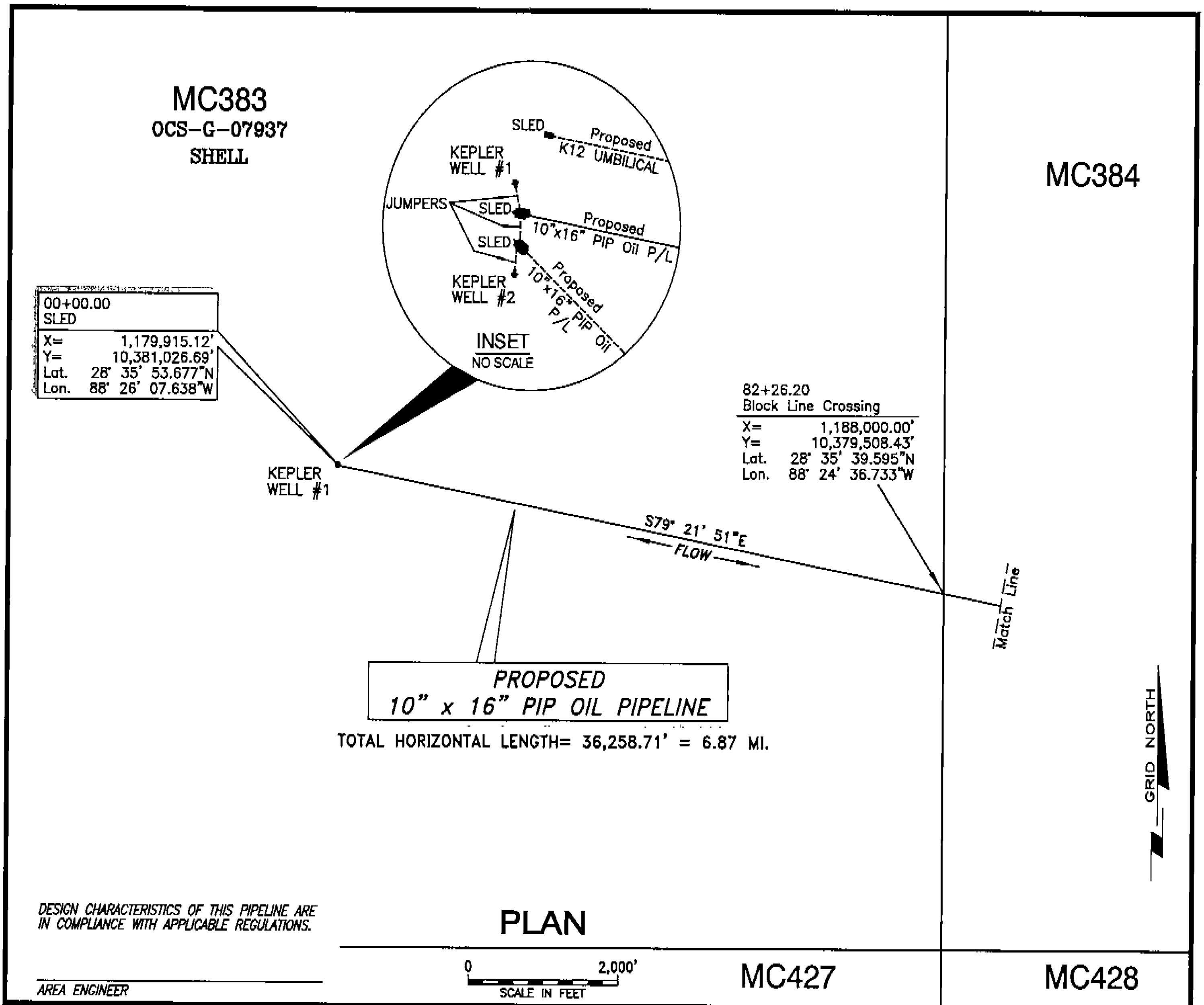
PROPOSED
10" x 16" PIP OIL PIPELINE
KEPLER WELL #1 TO ARIEL WELL #4
MISSISSIPPI CANYON AREA BLOCKS 383 TO 429
GULF OF MEXICO

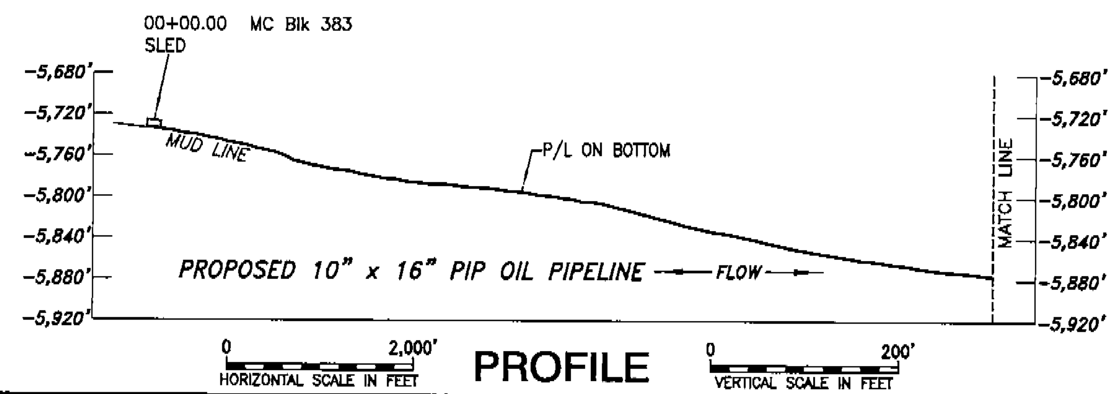
JOHN E. CHANCE & ASSOCIATES, INC. FUGRO

GEODETIC DATUM: NAD 1927
PROJECTION: U.T.M. 16
GRID UNITS: US SURVEY FEET

SCALE IN FEET 0 40,000'

Job No.: 01-1838	Date: 03/22/02	Drwn: MGK	Chart: 1 Of: 5
Dwgfile: H:\2001\011838\CAD\MARINE\1838COVRNORTH (B)			





THE RIGHT OF WAY OF THE PROPOSED PIPELINE IS ACCURATELY REPRESENTED.

STATE OF LOUISIANA
LIONEL J. CORMIER
REG. No. 4401
REGISTERED PROFESSIONAL LAND SURVEYOR

Lionel J. Cormier

REG. PROFESSIONAL LAND SURVEYOR NO. 4401
STATE OF LOUISIANA

R/W LIMITS
100'
PROPOSED PIPELINE
100'
R/W LIMITS

RIGHT-OF-WAY DETAIL

Printed: 3/22/02

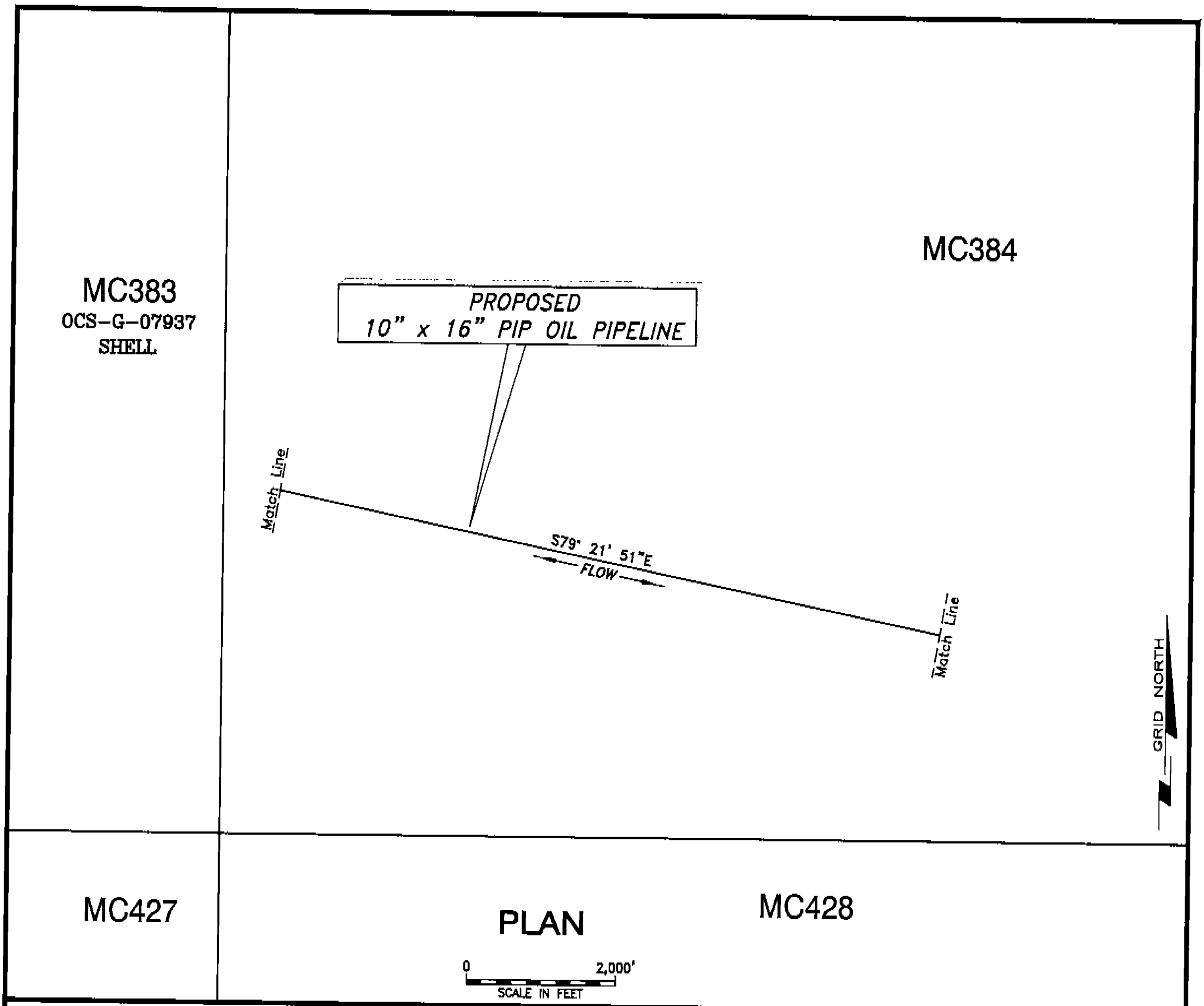
SHELL OFFSHORE INC.

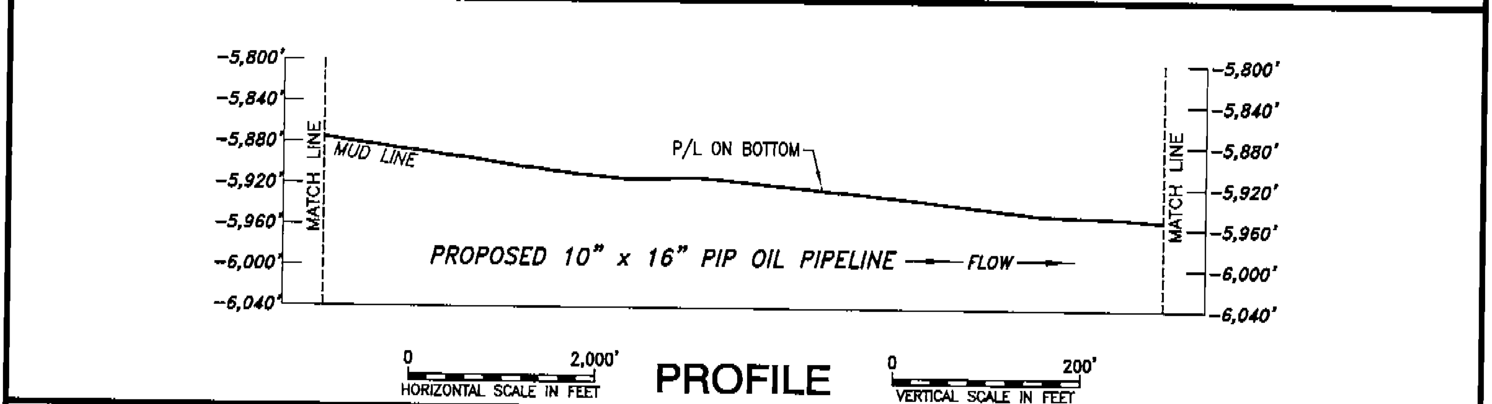
PROPOSED
10" x 16" PIP OIL PIPELINE
KEPLER WELL #1 TO ARIEL WELL #4
MISSISSIPPI CANYON AREA BLOCKS 383 TO 429
GULF OF MEXICO

JOHN E. CHANCE & ASSOCIATES, INC.

GEODETIC DATUM: NAD 1927 PROJECTION: U.T.M. 16 GRID UNITS: US SURVEY FEET	SCALE AS SHOWN

Job No.: 01-1838	Date: 03/22/02	Drwn: MGK	Chart: 2	Of: 5
Dwgfile: H:\2001\011838\CAD\MARINE\011838PPNORTH (B)				





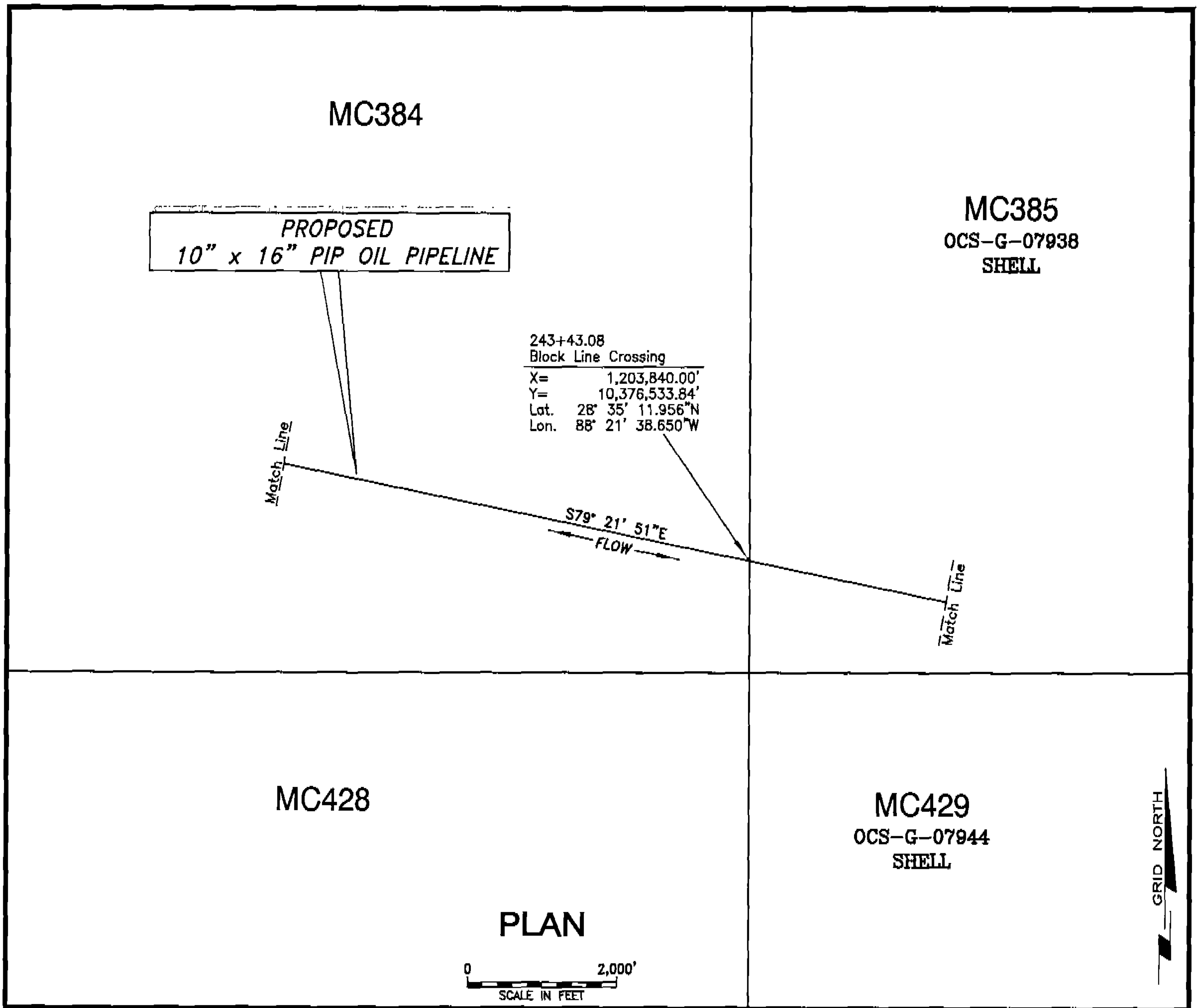
SHELL OFFSHORE INC.

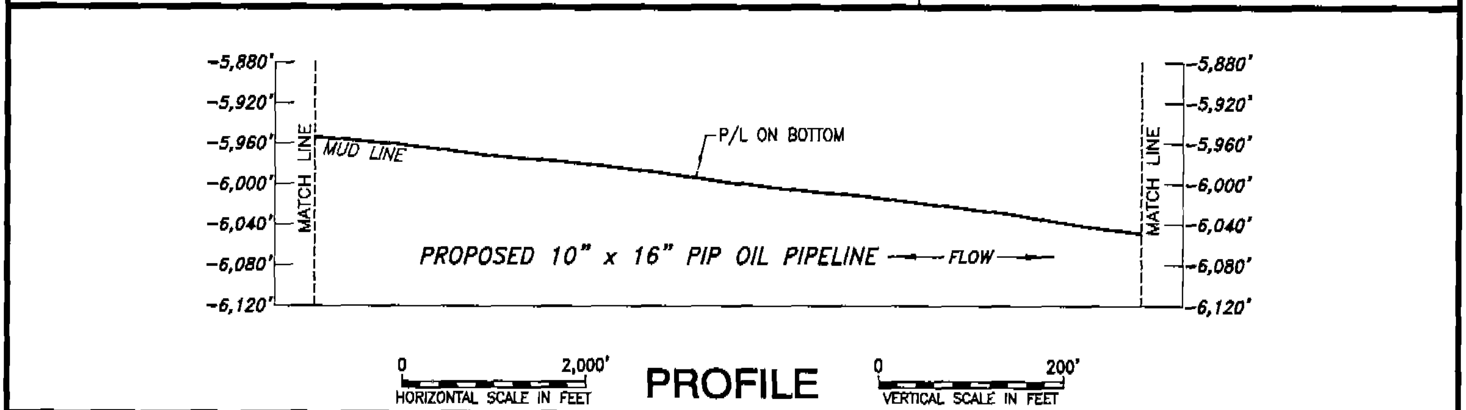
PROPOSED
10" x 16" PIP OIL PIPELINE
KEPLER WELL #1 TO ARIEL WELL #4
MISSISSIPPI CANYON AREA BLOCKS 383 TO 429
GULF OF MEXICO

JOHN E. CHANCE & ASSOCIATES, INC. FUGRO

GEODETIC DATUM: NAD 1927 PROJECTION: U.T.M. 16 GRID UNITS: US SURVEY FEET		SCALE AS SHOWN	
Job No.: 01-1838	Date: 03/22/02	Drwn: MGK	Chart: 3 Of: 5
Dwgfile: H:\2001\011838\CAD\MARINE\011838PPNORTH (B)			

Printed: 3/22/02





SHELL OFFSHORE INC.

PROPOSED
10" x 16" PIP OIL PIPELINE
KEPLER WELL #1 TO ARIEL WELL #4
MISSISSIPPI CANYON AREA BLOCKS 383 TO 429
GULF OF MEXICO

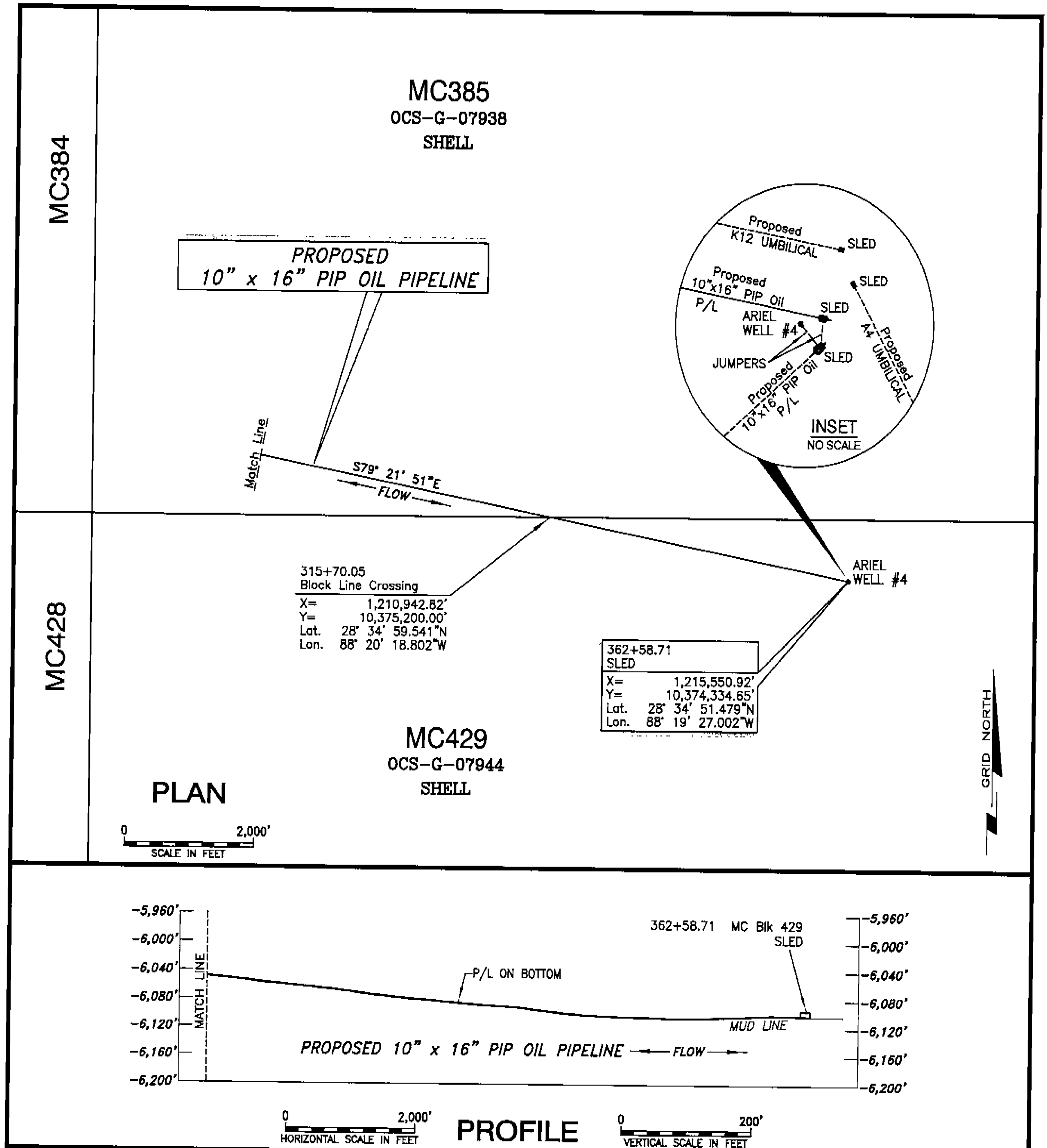
JOHN E. CHANCE & ASSOCIATES, INC. FUGRO

GEODETIC DATUM: NAD 1927
PROJECTION: U.T.M. 16
GRID UNITS: US SURVEY FEET

SCALE AS SHOWN

Job No.: 01-1838	Date: 03/22/02	Drwn: MGK	Chart: 4 Of: 5
Dwgfile: H:\2001\011838\CAD\MARINE\011838PPNORTH (B)			

Printed: 3/22/02



SHELL OFFSHORE INC.

PROPOSED
10" x 16" PIP OIL PIPELINE
KEPLER WELL #1 TO ARIEL WELL #4
MISSISSIPPI CANYON AREA BLOCKS 383 TO 429
GULF OF MEXICO

JOHN E. CHANCE & ASSOCIATES, INC. FUGRO

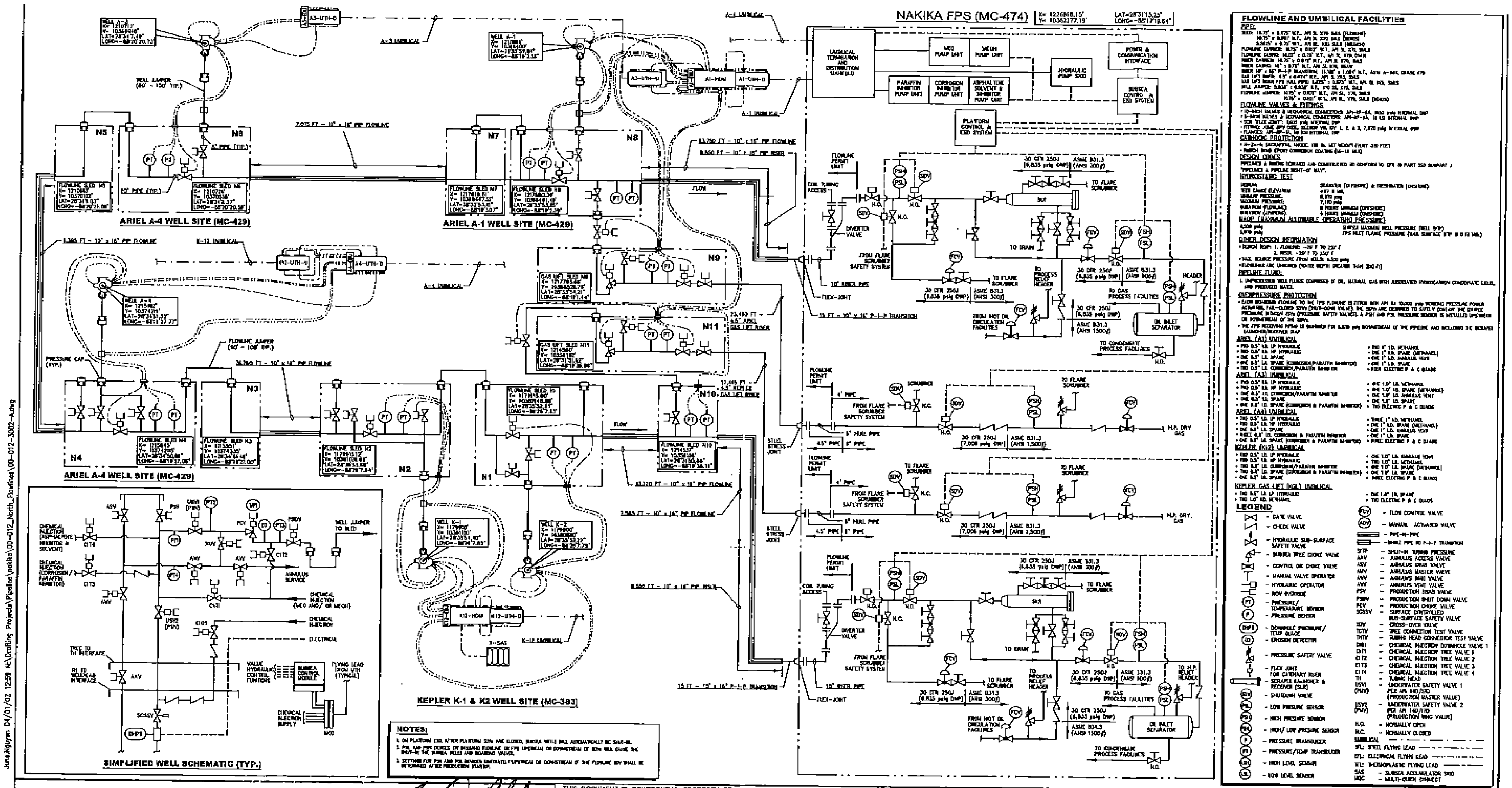
GEODETIC DATUM: NAD 1927 PROJECTION: U.T.M. 16 GRID UNITS: US SURVEY FEET	SCALE AS SHOWN

Job No.: 01-1838	Date: 03/22/02	Drwn: MGK	Chart: 5 Of: 5
Dwgfile: H:\2001\011838\CAD\MARINE\011838PPNORTH (B)			

Printed: 3/22/02

ATTACHMENT 2

Safety Schematic and Flowline Diagram for NaKika North Flowline Loop (Drawing 00-012-3002)



NOTES:

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04-02-02

TAP	A	ORIGINAL ISSUE	TAP	DN	03/27/02
APP'D	MARK	REVISION	CHK	BY	DATE

RELEASED FOR:

	LEAD ENGR.	DESIGN ENGR.	DRAFTER	DATE
PRELIMINARY				
BIDDING				
MATERIAL ORDER				
FABRICATION				
ERECTION				

SIEP Shell International Exploration and Production Inc.

NA KIKA NORTH FLOWLINES

OIL (10" x 16" PIP) FLOWLINE LOOP
SAFETY SCHEMATIC & FLOWLINE DIAGRAM
SUBSEA (MC-383) TO NAKIKA HOST (MC-474)

SCALE: NONE | 00-012-3002 | A

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ATTACHMENT 3

Detailed Calculations for Pipe Collapse Design

Calculation 1. Sled 5" Piping Collapse Design

Constants

Sea Water Specific Weight	$\gamma \equiv 64 \cdot \mathrm{lbf} \cdot \mathrm{ft}^{-3}$
Modulus of Elasticity of Steel	$E \equiv 29000\,\mathrm{ksi}$

Design Data

Outside Diameter for Pipe	$D = 5.563\mathrm{in}$
Pipeline Wall Thickness	$t = 0.75\mathrm{in}$
SMYS of Pipe	$Y = 65\mathrm{ksi}$
Maximum Water Depth at Calculation	$H_{max} = -6150\mathrm{ft}$

Pipe Collapse Design

The following is based on API RP 1111 (Limit State Design), 3rd edition, July, 1999It is also known as the Shell Formula. The most critical point along the entire pipeline route is the pipe at the maximum water depth.

$H_{max} = -6150\mathrm{ft}$

$P_{ex\_max} := \gamma \cdot |H_{max}|$ $\quad P_{ex\_max} = 2733\mathrm{psig}$ *_maximum external pressure at calculation*

Pipeline Collapse Pressure

$P_y := 2 \cdot Y \cdot \frac{t}{D}$ $\quad P_y = 17528\mathrm{psi}$ *_yield pressure at collapse*

$P_e := 2.2 \cdot \left(\frac{t}{D}\right)^3 \cdot E$ $\quad P_e = 156385\mathrm{psi}$ *_elastic collapse pressure*

$P_c := \frac{P_y \cdot P_e}{\sqrt{P_y^{\,2} + P_e^{\,2}}}$ $\quad P_c = 17419\mathrm{psi}$ *_collapse pressure of the pipeline*

Check Against Pipeline Collapse

$\mathrm{CollapseF} := \frac{P_c}{P_{ex\_max}}$ $\quad \mathrm{CollapseF} = 6.37$

$\mathrm{CheckP_c} := \mathrm{if}(\mathrm{CollapseF} > 1.5, \text{"OK"}, \text{"Not OK"})$

$\mathrm{CheckP_c} = \text{"OK"}$

Calculation 2. Sled Pipe Spool Collapse Design

Constants

Sea Water Specific Weight $\gamma \equiv 64 \cdot \text{lbf} \cdot \text{ft}^{-3}$

Modulus of Elasticity of Steel $E \equiv 29000\text{ksi}$

Design Data

Outside Diameter for Pipe $D = 10.75\text{in}$

Pipeline Wall Thickness $t = 0.875\text{in}$

SMYS of Pipe $Y = 70\text{ksi}$

Maximum Water Depth at Calculation $H_{max} = -6150\text{ft}$

Pipe Collapse Design

The following is based on API RP 1111 (Limit State Design), 3rd edition, July, 1999It is also known as the Shell Formula. The most critical point along the entire pipeline route is the pipe at the maximum water depth.

$H_{max} = -6150\text{ft}$

$P_{ex\_max} := \gamma \cdot |H_{max}|$ $P_{ex\_max} = 2733\text{psig}$ *_maximum external pressure at calculation*

Pipeline Collapse Pressure

$P_y := 2 \cdot Y \cdot \frac{t}{D}$ $P_y = 11395\text{psi}$ *_yield pressure at collapse*

$P_e := 2.2 \cdot \left(\frac{t}{D}\right)^3 \cdot E$ $P_e = 34405\text{psi}$ *_elastic collapse pressure*

$P_c := \frac{P_y \cdot P_e}{\sqrt{P_y^2 + P_e^2}}$ $P_c = 10817\text{psi}$ *_collapse pressure of the pipeline*

Check Against Pipeline Collapse

$\text{CollapseF} := \frac{P_c}{P_{ex\_max}}$ $\text{CollapseF} = 3.96$

$\text{CheckP}_c := \text{if}(\text{CollapseF} > 1.5, \text{"OK"}, \text{"Not OK"})$

$\text{CheckP}_c = \text{"OK"}$

Calculation 3. Flowline Casing Collapse Design

Constants

Sea Water Specific Weight $\gamma \equiv 64 \cdot \mathrm{lbf} \cdot \mathrm{ft}^{-3}$

Modulus of Elasticity of Steel $E \equiv 29000\,\mathrm{ksi}$

Design Data

Outside Diameter for Pipe $D = 16\,\mathrm{in}$

Pipeline Wall Thickness $t = 0.75\,\mathrm{in}$

SMYS of Pipe $Y = 70\,\mathrm{ksi}$

Maximum Water Depth at Calculation $H_{max} = -6150\,\mathrm{ft}$

Pipe Collapse Design

The following is based on API RP 1111 (Limit State Design), 3rd edition, July, 1999It is also known as the Shell Formula. The most critical point along the entire pipeline route is the pipe at the maximum water depth.

$H_{max} = -6150\,\mathrm{ft}$

$P_{ex\_max} := \gamma \cdot |H_{max}|$ $\quad P_{ex\_max} = 2733\,\mathrm{psig}$ *_maximum external pressure at calculation*

Pipeline Collapse Pressure

$P_y := 2 \cdot Y \cdot \dfrac{t}{D}$ $\quad P_y = 6563\,\mathrm{psi}$ *_yield pressure at collapse*

$P_e := 2.2 \cdot \left(\dfrac{t}{D}\right)^3 \cdot E$ $\quad P_e = 6571\,\mathrm{psi}$ *_elastic collapse pressure*

$P_c := \dfrac{P_y \cdot P_e}{\sqrt{P_y^{\,2} + P_e^{\,2}}}$ $\quad P_c = 4643\,\mathrm{psi}$ *_collapse pressure of the pipeline*

Check Against Pipeline Collapse

$\mathrm{CollapseF} := \dfrac{P_c}{P_{ex\_max}}$ $\quad \mathrm{CollapseF} = 1.7$

$\mathrm{CheckP_c} := \mathrm{if}(\mathrm{CollapseF} > 1.5, \text{"OK"}, \text{"Not OK"})$

$\mathrm{CheckP_c} = \text{"OK"}$

ATTACHMENT 4

Detailed Calculations for Pipe Internal Pressure Design

Calculation 4. N2 Sled 5" Piping Pressure Design (1/3)

(All Pressures are gauge Pressures)

Constants

Sea Water Specific Weight	$\gamma \equiv 64 \cdot \text{lbf} \cdot \text{ft}^{-3}$
Modulus of Elasticity of Steel	$E \equiv 29000\,\text{ksi}$

Design Data

Outside Diameter for Pipe	$D = 5.563\text{in}$
Pipe Wall Thickness	$t = 0.75\text{in}$
SMYS of Pipe	$Y = 65\text{ksi}$
Water Depth at Well with the Maximum SITP	$H_{A4} = -6150\text{ft}$
Mean Sea Level Elevation (MSL)	$H_{msl} = 0\,\text{ft}$
Elevation at the Riser Top	$H_{top} = 67\,\text{ft}$
Water Depth at Calculation Location	$H_{local} = -5800\text{ft}$
Maximum SITP of the Flowline Loop, at Well A-4	$P_{sitp} = 6500\text{psig}$
Maxiumu SITP at Mean Sea Level Elevation	$P_{msl} = 5600\text{psig}$
Minimum Design Pressure of Sled Components	$P_{fitting} = 6650\text{psig}$
Construction Design Factor (B31.8) (Line Pipe)	$F = 0.72$
Longitudinal Joint Factor (DSAW or Seamless Pipe)	$f_e = 1$
Temperature Derating Factor (B31.8, Temp. <=250 F)	$f_t = 1$

Calculation 4. N2 Sled 5" Piping Pressure Design (2/3)

1. Internal Pressure Design

Local SITP Calculation

$P_{gradient} := \dfrac{P_{sitp} - P_{msl}}{H_{A4} - H_{msl}}$ $\quad P_{gradient} = -0.146 ft^{-1} psig$ $\quad$ *_pressure gradient assumption*

$P_{sitp1} := P_{sitp} - P_{gradient} \cdot (H_{A4} - H_{local})$ $\quad P_{sitp1} = 6449 psig$ $\quad$ *_SITP at calculation location*

$P_{top} := P_{sitp} - P_{gradient} \cdot (H_{A4} - H_{top})$ $\quad P_{top} = 5590 psig$ $\quad$ *_SITP at riser top of +67 ft elevation*

Internal Design Pressure (B31.8)

The sled piping is exposed to external pressure.

$P_{ex} := \gamma \cdot |H_{local}|$ $\quad P_{ex} = 2578 psig$ $\quad$ *_external pressure*

$P_i := P_{ex} + \dfrac{(2 \cdot Y \cdot t \cdot f_e \cdot F \cdot f_t)}{D}$ $\quad P_i = 15198 psig$ $\quad$ *_internal design pressure B31.8*

$CheckP_{i1} := if(P_i > P_{sitp1}, \text{"OK"}, \text{"Not OK"})$ $\quad CheckP_{i1} = \text{"OK"}$

Hoop Stress during Hydrotest

The onshore hydrotest pressure for all the NaKika North Sleds is 8,300 to 8,350 psig based on approximately 1.25 times the minimum design pressure of the sled components. The required offshore hydrotest pressure is 1.25 times the SITP at riser top (+67ft). The Hoop Stress during hydrotest due to maximuminternal net pressure should not exceed 95% of SMYS.

A. Onshore Test

$P_{Hydro} := 8350 psig$ $\quad$ *_maximum allowable hydrotest pressure on Sled*

$P_{tnet} := P_{Hydro}$ $\quad P_{tnet} = 8350 psig$ $\quad$ *_internal net pressure*

$SH := \dfrac{P_{tnet} \cdot D}{2 \cdot t}$ $\quad SH = 31 ksi$ $\quad$ *_hoop stress, based on thin wall OD*

$\%SMYS := \dfrac{SH}{Y}$ $\quad \%SMYS = 48\%$

$CheckSH := if(\%SMYS < 95\%, \text{"OK"}, \text{"Not OK"})$ $\quad CheckSH = \text{"OK"}$

Calculation 4. N2 Sled 5" Piping Pressure Design (3/3)

B. Offshore Test

$P_{ex} = 2578\text{psig}$		*_external pressure*
$P_{fluid} := (H_{top} - H_{local})\cdot\gamma$	$P_{fluid} = 2608\text{psig}$	*_testing water head pressure*
$P_{Hydro} := 1.25\cdot P_{top} + P_{fluid}$	$P_{Hydro} = 9595\text{psig}$	*_local minimum hydrotest pressure*
$P_{Hydro\_max} := P_{Hydro} + 200\cdot\text{psig}$	$P_{Hydro\_max} = 9795\text{psig}$	*_maximum hydrotest pressure*
$P_{tnet\_max} := P_{Hydro\_max} - P_{ex}$	$P_{tnet\_max} = 7218\text{psig}$	*_maximum internal net test pressure*
$SH := \dfrac{P_{tnet\_max}\cdot D}{2\cdot t}$	$SH = 27\text{ksi}$	*_hoop stress, based on thin wall OD*
$\%SMYS := \dfrac{SH}{Y}$	$\%SMYS = 41\%$	
CheckSH := if(%SMYS < 95%, "OK", "Not OK")		CheckSH = "OK"

2. Offshore Hydrostatic Test Pressure and MAOP

The required hydrostatic test (hydrotest) pressure is 1.25 of the top SITP. The local test pressure should not be less than 1.25 of the local SITP. The effective hydrotest pressure is the net pressure the pipe experiences. For internal carrier pipe not subjected to hydrostatic pressure, the effective test pressure is the same as the hydrotest internal pressure. The Maximum Allowable Operating Pressure (MAOP) is the lowest of: a) Pipe Design pressure; b) 80% of Minimum Hydrotest Pressure and c) Minimum Design Pressure for Valves, Flanges, Fittings or other Components where applicable.

Effective Hydrotest Net Pressure

$P_{tnet} := P_{Hydro} - P_{ex}$	$P_{tnet} = 7018\text{psig}$	*_minimum hydrotest net pressure*
$P_{eff} := P_{tnet}$	$P_{eff} = 7018\text{psig}$	*_effective test pressure*
$P_{req} := 1.25\cdot P_{sitp1} - P_{ex}$	$P_{req} = 5483\text{psig}$	*_required local net test pressure*
$\text{CheckP}_{eff} := \text{if}(P_{eff} \geq P_{req}, \text{"OK"}, \text{"Not OK"})$		$\text{CheckP}_{eff} = \text{"OK"}$

MAOP

$MAOP_{hydro} := 0.80\cdot P_{eff} + P_{ex}$		*_MAOP based on hydrotest pressure*
$MAOP_{hydro} = 8192\text{psig}$		
$P_{fittingH} := P_{fitting} + \gamma\cdot\lvert H_{local}\rvert$	$P_{fittingH} = 9228\text{psig}$	*_minimum design pressure for the components on sled at sled water depth*
$MAOP := \min(MAOP_{hydro}, P_i, P_{fittingH})$		*_MAOP at the calculation location*
$MAOP = 8192\text{psig}$		
$\text{CheckMAOP} := \text{if}(MAOP \geq P_{sitp1}, \text{"OK"}, \text{"Not OK"})$		CheckMAOP = "OK"

Calculation 5. N2 Sled 10" Pipe Spool Pressure Design (1/3)

(All Pressures are gauge Pressures)

Constants

Sea Water Specific Weight $\gamma \equiv 64 \cdot \mathrm{lbf} \cdot \mathrm{ft}^{-3}$

Modulus of Elasticity of Steel $E \equiv 29000\,\mathrm{ksi}$

Design Data

Outside Diameter for Pipe	$D = 10.75\mathrm{in}$
Pipe Wall Thickness	$t = 0.875\mathrm{in}$
SMYS of Pipe	$Y = 70\,\mathrm{ksi}$
Water Depth at Well with the Maximum SITP	$H_{A4} = -6150\mathrm{ft}$
Mean Sea Level Elevation (MSL)	$H_{msl} = 0\,\mathrm{ft}$
Elevation at the Riser Top	$H_{top} = 67\,\mathrm{ft}$
Water Depth at Calculation Location	$H_{local} = -5800\mathrm{ft}$
Maximum SITP of the Flowline Loop, at Well A-4	$P_{sitp} = 6500\mathrm{psig}$
Maxiumu SITP at Mean Sea Level Elevation	$P_{msl} = 5600\mathrm{psig}$
Minimum Design Pressure of Sled Components	$P_{fitting} = 6650\mathrm{psig}$
Construction Design Factor (B31.8) (Line Pipe)	$F = 0.72$
Longitudinal Joint Factor (DSAW or Seamless Pipe)	$f_e = 1$
Temperature Derating Factor (B31.8, Temp. <=250 F)	$f_t = 1$

Calculation 5. N2 Sled 10" Pipe Spool Pressure Design (2/3)

1. Internal Pressure Design

Local SITP Calculation

$P_{gradient} := \frac{P_{sitp} - P_{msl}}{H_{A4} - H_{msl}}$ $P_{gradient} = -0.146 ft^{-1} psig$ _pressure gradient assumption

$P_{sitp1} := P_{sitp} - P_{gradient} \cdot (H_{A4} - H_{local})$ $P_{sitp1} = 6449 psig$ _SITP at calculation location

$P_{top} := P_{sitp} - P_{gradient} \cdot (H_{A4} - H_{top})$ $P_{top} = 5590 psig$ _SITP at riser top of +67 ft elevation

Internal Design Pressure (B31.8)

The sled piping is exposed to external pressure.

$P_{ex} := \gamma \cdot |H_{local}|$ $P_{ex} = 2578 psig$ _external pressure

$P_i := P_{ex} + \frac{(2 \cdot Y \cdot t \cdot f_e \cdot F \cdot f_t)}{D}$ $P_i = 10782 psig$ _internal design pressure B31.8

$CheckP_{i1} := if(P_i > P_{sitp1}, "OK", "Not OK")$ $CheckP_{i1} = "OK"$

Hoop Stress during Hydrotest

The onshore hydrotest pressure for all the NaKika North Sleds is 8,300 to 8,350 psig based on approximately 1.25 times the minimum design pressure of the sled components. The required offshore hydrotest pressure is 1.25 times the SITP at riser top (+67ft). The Hoop Stress during hydrotest due to maximuminternal net pressure should not exceed 95% of SMYS.

A. Onshore Test

$P_{Hydro} := 8350 psig$ _maximum allowable hydrotest pressure on Sled

$P_{tnet} := P_{Hydro}$ $P_{tnet} = 8350 psig$ _internal net pressure

$SH := \frac{P_{tnet} \cdot D}{2 \cdot t}$ $SH = 51 ksi$ _hoop stress, based on thin wall OD

$\%SMYS := \frac{SH}{Y}$ $\%SMYS = 73\%$

$CheckSH := if(\%SMYS < 95\%, "OK", "Not OK")$ $CheckSH = "OK"$

Calculation 5. N2 Sled 10" Pipe Spool Pressure Design (3/3)

B. Offshore Test

$P_{ex} = 2578\text{psig}$		*_external pressure*
$P_{fluid} := (H_{top} - H_{local})\cdot\gamma$	$P_{fluid} = 2608\text{psig}$	*_testing water head pressure*
$P_{Hydro} := 1.25\cdot P_{top} + P_{fluid}$	$P_{Hydro} = 9595\text{psig}$	*_local minimum hydrotest pressure*
$P_{Hydro\_max} := P_{Hydro} + 200\cdot\text{psig}$	$P_{Hydro\_max} = 9795\text{psig}$	*_maximum hydrotest pressure*
$P_{tnet\_max} := P_{Hydro\_max} - P_{ex}$	$P_{tnet\_max} = 7218\text{psig}$	*_maximum internal net test pressure*
$SH := \dfrac{P_{tnet\_max}\cdot D}{2\cdot t}$	$SH = 44\text{ksi}$	*_hoop stress, based on thin wall OD*
$\%SMYS := \dfrac{SH}{Y}$	$\%SMYS = 63\%$	
$CheckSH := if(\%SMYS < 95\%, \text{"OK"}, \text{"Not OK"})$		$CheckSH = \text{"OK"}$

2. Offshore Hydrostatic Test Pressure and MAOP

The required hydrostatic test (hydrotest) pressure is 1.25 of the top SITP. The local test pressure should not be less than 1.25 of the local SITP. The effective hydrotest pressure is the net pressure the pipe experiences. For internal carrier pipe not subjected to hydrostatic pressure, the effective test pressure is the same as the hydrotest internal pressure. The Maximum Allowable Operating Pressure (MAOP) is the lowest of: a) Pipe Design pressure; b) 80% of Minimum Hydrotest Pressure and c) Minimum Design Pressure for Valves, Flanges, Fittings or other Components where applicable.

Effective Hydrotest Net Pressure

$P_{tnet} := P_{Hydro} - P_{ex}$	$P_{tnet} = 7018\text{psig}$	*_minimum hydrotest net pressure*
$P_{eff} := P_{tnet}$	$P_{eff} = 7018\text{psig}$	*_effective test pressure*
$P_{req} := 1.25\cdot P_{sitp1} - P_{ex}$	$P_{req} = 5483\text{psig}$	*_required local net test pressure*
$CheckP_{eff} := if(P_{eff} \ge P_{req}, \text{"OK"}, \text{"Not OK"})$		$CheckP_{eff} = \text{"OK"}$

MAOP

$MAOP_{hydro} := 0.80\cdot P_{eff} + P_{ex}$		*_MAOP based on hydrotest pressure*
$MAOP_{hydro} = 8192\text{psig}$		
$P_{fittingH} := P_{fitting} + \gamma\cdot\lvert H_{local}\rvert$	$P_{fittingH} = 9228\text{psig}$	*_minimum design pressure for the components on sled at sled water depth*
$MAOP := min(MAOP_{hydro}, P_i, P_{fittingH})$		*_MAOP at the calculation location*
$MAOP = 8192\text{psig}$		
$CheckMAOP := if(MAOP \ge P_{sitp1}, \text{"OK"}, \text{"Not OK"})$		$CheckMAOP = \text{"OK"}$

Calculation 6. Flowline Carrier Pipe Pressure Design (1/3)

(All Pressures are gauge Pressures)

Calculation Locations

Calculation Location 1: Flowline Carrier Pipe at K-1 Start-Up Sled (N2)

Calculation Location 2: Flowline Carrier Pipe at A-4 Sled (N3)

Constants

Sea Water Specific Weight	$\gamma \equiv 64 \cdot \mathrm{lbf} \cdot \mathrm{ft}^{-3}$
Modulus of Elasticity of Steel	$E \equiv 29000\,\mathrm{ksi}$

Design Data

Outside Diameter for Pipe	$D = 10.75\mathrm{in}$
Pipe Wall Thickness	$t = 0.812\mathrm{in}$
SMYS of Pipe	$Y = 70\mathrm{ksi}$
Water Depth at the Well with the Max. Shut-In-Tube-Pressure (SITP)	$H_{A4} = -6150\mathrm{ft}$
Mean Sea Level Elevation (MSL)	$H_{msl} = 0\,\mathrm{ft}$
Elevation at the Riser Top	$H_{top} = 67\,\mathrm{ft}$
Water Depth at Calculation Location 1	$H_{local1} = -5800\mathrm{ft}$
Water Depth at Calculation Location 2	$H_{local2} = -6150\mathrm{ft}$
Maximum SITP of the Flowline Loop, at Well A-4	$P_{sitp} = 6500\mathrm{psig}$
Maximum SITP at Mean Sea Level Elevation	$P_{msl} = 5600\mathrm{psig}$
Minimum Design Pressure of Sled Components	$P_{fitting} = 6650\mathrm{psig}$
Construction Design Factor (B31.8) (Line Pipe)	$F = 0.72$
Longitudinal Joint Factor (DSAW or Seamless Pipe)	$f_e = 1$
Temperature Derating Factor (B31.8, Temp. <=250 F)	$f_t = 1$

Calculation 6. Flowline Carrier Pipe Pressure Design (2/3)

Location 1, Flowline at K-1 Sled

1. Internal Pressure Design

Local SITP Calculation

$P_{gradient} := \dfrac{P_{sitp} - P_{msl}}{H_{A4} - H_{msl}}$ $P_{gradient} = -0.146ft^{-1}$ psig _pressure gradient assumption

$P_{sitp1} := P_{sitp} - P_{gradient}(H_{A4} - H_{local1})$ $P_{sitp1} = 6449psig$ _SITP at calculation location

$P_{top} := P_{sitp} - P_{gradient}(H_{A4} - H_{top})$ $P_{top} = 5590psig$ _SITP at riser top of +67 ft elevation

Internal Design Pressure (B31.8)

$P_{ex} := 0psi$ _no external pressure

$P_i := P_{ex} + \dfrac{(2 \cdot Y \cdot t \cdot f_e \cdot F \cdot f_t)}{D}$ $P_i = 7614psig$ _internal Design Pressure B31.8

$CheckP_{i1} := if(P_i > P_{sitp1}, \text{"OK"}, \text{"Not OK"})$ $CheckP_{i1} = \text{"OK"}$

Hoop Stress during Hydrotest

$P_{ex} = 0psi$ _external pressure

$P_{fluid} := (H_{top} - H_{local1}) \cdot \gamma$ $P_{fluid} = 2608psig$ _testing water head pressure

$P_{Hydro} := 1.25 \cdot P_{top} + P_{fluid}$ $P_{Hydro} = 9595psig$ _minimum hydrotest pressure

$P_{Hydro\_max} := P_{Hydro} + 200 \cdot psig$ $P_{Hydro\_max} = 9795psig$ _maximum hydrotest pressure

$P_{tnet\_max} := P_{Hydro\_max} - P_{ex}$ $P_{tnet\_max} = 9795psig$ _maximum internal net test pressure

$SH := \dfrac{P_{tnet\_max} \cdot D}{2 \cdot t}$ $SH = 65ksi$ _hoop stress, based on thin wall OD

$\%SMYS := \dfrac{SH}{Y}$ $\%SMYS = 93\%$

$CheckSH := if(\%SMYS < 95\%, \text{"OK"}, \text{"Not OK"})$ $CheckSH = \text{"OK"}$

2. Hydrostatic Test Pressure and MAOP

The required hydrostatic test (hydrotest) pressure is 1.25 of the top SITP. The local test pressure should not be less than 1.25 of the local SITP. The effective hydrotest pressure is the net pressure the pipe experiences. For internal carrier pipe not subjected to hydrostatic pressure, the effective test pressure is the same as the hydrotest internal pressure. The Maximum Allowable Operating Pressure (MAOP) is the lowest of: a) Pipe Design pressure; b) 80% of Minimum Hydrotest Pressure and c) Minimum Design Pressure for Valves, Flanges, Fittings or other Components where applicable.

Effective Hydrotest Net Pressure

$P_{tnet} := P_{Hydro} - P_{ex}$ $P_{tnet} = 9595psig$ _minimum hydrotest net pressure

$P_{eff} := P_{tnet}$ $P_{eff} = 9595psig$ _effective test pressure

$P_{req} := 1.25 \cdot P_{sitp1} - P_{ex}$ $P_{req} = 8061psig$ _required local net test pressure

$CheckP_{eff} := if(P_{eff} \geq P_{req}, \text{"OK"}, \text{"Not OK"})$ $CheckP_{eff} = \text{"OK"}$

MAOP

$MAOP_{hydro} := 0.80 \cdot P_{eff} + P_{ex}$ _MAOP based on hydrotest pressure

$MAOP_{hydro} = 7676psig$

$P_{fittingH} := P_{fitting} + \gamma \cdot |H_{local1}|$ $P_{fittingH} = 9228psig$ _design pressure for the components on sled at sled water depth

$MAOP := min(MAOP_{hydro}, P_i, P_{fittingH})$ _MAOP at the calculation location

$MAOP = 7614psig$

$CheckMAOP := if(MAOP \geq P_{sitp1}, \text{"OK"}, \text{"Not OK"})$ $CheckMAOP = \text{"OK"}$

Calculation 6. Flowline Carrier Pipe Pressure Design (3/3)

Location 2, Flowline at A-4 Sled

1. Internal Pressure Design

Local SITP Calculation

$P_{gradient} := \dfrac{P_{sitp} - P_{msl}}{H_{A4} - H_{msl}}$	$P_{gradient} = -0.146 ft^{-1}\,psig$	*_pressure gradient assumption*
$P_{sitp2} := P_{sitp} - P_{gradient} \cdot (H_{A4} - H_{local2})$	$P_{sitp2} = 6500 psig$	*_SITP at calculation location*
$P_{top} := P_{sitp} - P_{gradient} \cdot (H_{A4} - H_{top})$	$P_{top} = 5590 psig$	*_SITP at riser top of +67 ft elevation*

Internal Design Pressure (B31.8)

$P_{ex} := 0 \cdot psig$		*_pipe is NOT exposed to external pressure*
$P_i := P_{ex} + \dfrac{(2 \cdot Y \cdot t \cdot f_e \cdot F \cdot f_t)}{D}$	$P_i = 7614 psig$	*_internal Design Pressure B31.8*
$CheckP_{i1} := if(P_i > P_{sitp2}, \text{"OK"}, \text{"Not OK"})$		$CheckP_{i1} = \text{"OK"}$

Hoop Stress during Hydrotest

$P_{ex} = 0 psi$		*_external pressure*
$P_{fluid} := (H_{top} - H_{local2}) \cdot \gamma$	$P_{fluid} = 2763 psig$	*_testing water head pressure*
$P_{Hydro} := 1.25 \cdot P_{top} + P_{fluid}$	$P_{Hydro} = 9751 psig$	*_minimum hydrotest pressure*
$P_{Hydro\_max} := P_{Hydro} + 200 \cdot psig$	$P_{Hydro\_max} = 9951 psig$	*_maximum hydrotest pressure*
$P_{tnet\_max} := P_{Hydro\_max} - P_{ex}$	$P_{tnet\_max} = 9951 psig$	*_maximum internal net test pressure*
$SH := \dfrac{P_{tnet\_max} \cdot D}{2 \cdot t}$	$SH = 66 ksi$	*_hoop stress, based on thin wall OD*
$\%SMYS := \dfrac{SH}{Y}$	$\%SMYS = 94\%$	
$CheckSH := if(\%SMYS < 95\%, \text{"OK"}, \text{"Not OK"})$		$CheckSH = \text{"OK"}$

2. Hydrostatic Test Pressure and MAOP

The required hydrostatic test (hydrotest) pressure is 1.25 of the top SITP. The local test pressure should not be less than 1.25 of the local SITP. The effective hydrotest pressure is the net pressure the pipe experiences. For internal carrier pipe not subjected to hydrostatic pressure, the effective test pressure is the same as the hydrotest internal pressure. The Maximum Allowable Operating Pressure (MAOP) is the lowest of: a) Pipe Design pressure; b) 80% of Minimum Hydrotest Pressure and c) Minimum Design Pressure for Valves, Flanges, Fittings or other Components where applicable.

Effective Hydrotest Net Pressure

$P_{tnet} := P_{Hydro} - P_{ex}$	$P_{tnet} = 9751 psig$	*_minimum net hydrotest pressure*
$P_{eff} := P_{tnet}$	$P_{eff} = 9751 psig$	*_effective test pressure*
$P_{req} := 1.25 \cdot P_{sitp2} - P_{ex}$	$P_{req} = 8125 psig$	*_required local net test pressure*
$CheckP_{eff} := if(P_{eff} \ge P_{req}, \text{"OK"}, \text{"Not OK"})$		$CheckP_{eff} = \text{"OK"}$

MAOP

$MAOP_{hydro} := 0.80 \cdot P_{eff} + P_{ex}$	*_MAOP based on hydrotest pressure*
$MAOP_{hydro} = 7801 psig$	
$MAOP := min(MAOP_{hydro}, P_i)$	*_MAOP at the calculation location (no components at this location)*
$MAOP = 7614 psig$	
$CheckMAOP := if(MAOP \ge P_{sitp2}, \text{"OK"}, \text{"Not OK"})$	$CheckMAOP = \text{"OK"}$

Calculation 7. N3 Sled 5" Piping Pressure Design (1/3)

(All Pressures are gauge Pressures)

Constants

Sea Water Specific Weight	$\gamma \equiv 64 \cdot \text{lbf} \cdot \text{ft}^{-3}$
Modulus of Elasticity of Steel	$E \equiv 29000 \text{ksi}$

Design Data

Outside Diameter for Pipe	$D = 5.563\text{in}$
Pipe Wall Thickness	$t = 0.75\text{in}$
SMYS of Pipe	$Y = 65\text{ksi}$
Water Depth at Well with the Maximum SITP	$H_{A4} = -6150\text{ft}$
Mean Sea Level Elevation (MSL)	$H_{msl} = 0\,\text{ft}$
Elevation at the Riser Top	$H_{top} = 67\,\text{ft}$
Water Depth at Calculation Location	$H_{local} = -6150\text{ft}$
Maximum SITP of the Flowline Loop, at Well A-4	$P_{sitp} = 6500\text{psig}$
Maxiumu SITP at Mean Sea Level Elevation	$P_{msl} = 5600\text{psig}$
Minimum Design Pressure of Sled Components	$P_{fitting} = 6650\text{psig}$
Construction Design Factor (B31.8) (Line Pipe)	$F = 0.72$
Longitudinal Joint Factor (DSAW or Seamless Pipe)	$f_e = 1$
Temperature Derating Factor (B31.8, Temp. <=250 F)	$f_t = 1$

Calculation 7. N3 Sled 5" Piping Pressure Design (2/3)

1. Internal Pressure Design

Local SITP Calculation

$P_{gradient} := \frac{P_{sitp} - P_{msl}}{H_{A4} - H_{msl}}$ $P_{gradient} = -0.146ft^{-1} psig$ *_pressure gradient assumption*

$P_{sitp1} := P_{sitp} - P_{gradient} \cdot (H_{A4} - H_{local})$ $P_{sitp1} = 6500psig$ *_SITP at calculation location*

$P_{top} := P_{sitp} - P_{gradient} \cdot (H_{A4} - H_{top})$ $P_{top} = 5590psig$ *_SITP at riser top of +67 ft elevation*

Internal Design Pressure (B31.8)

The sled piping is exposed to external pressure.

$P_{ex} := \gamma \cdot |H_{local}|$ $P_{ex} = 2733psig$ *_external pressure*

$P_i := P_{ex} + \frac{(2 \cdot Y \cdot t \cdot f_e \cdot F \cdot f_t)}{D}$ $P_i = 15354psig$ *_internal design pressure B31.8*

$CheckP_{i1} := if(P_i > P_{sitp1}, \text{"OK"}, \text{"Not OK"})$ $CheckP_{i1} = \text{"OK"}$

Hoop Stress during Hydrotest

The onshore hydrotest pressure for all the NaKika North Sleds is 8,300 to 8,350 psig based on approximately 1.25 times the minimum design pressure of the sled components. The required offshore hydrotest pressure is 1.25 times the SITP at riser top (+67ft). The Hoop Stress during hydrotest due to maximuminternal net pressure should not exceed 95% of SMYS.

A. Onshore Test

$P_{Hydro} := 8350 psig$ *_maximum allowable hydrotest pressure on Sled*

$P_{tnet} := P_{Hydro}$ $P_{tnet} = 8350psig$ *_internal net pressure*

$SH := \frac{P_{tnet} \cdot D}{2 \cdot t}$ $SH = 31 ksi$ *_hoop stress, based on thin wall OD*

$\%SMYS := \frac{SH}{Y}$ $\%SMYS = 48\%$

$CheckSH := if(\%SMYS < 95\%, \text{"OK"}, \text{"Not OK"})$ $CheckSH = \text{"OK"}$

Calculation 7. N3 Sled 5" Piping Pressure Design (3/3)

B. Offshore Test

$P_{ex} = 2733psig$		*_external pressure*
$P_{fluid} := (H_{top} - H_{local})\cdot\gamma$	$P_{fluid} = 2763psig$	*_testing water head pressure*
$P_{Hydro} := 1.25\cdot P_{top} + P_{fluid}$	$P_{Hydro} = 9751psig$	*_local minimum hydrotest pressure*
$P_{Hydro\_max} := P_{Hydro} + 200\cdot psig$	$P_{Hydro\_max} = 9951psig$	*_maximum hydrotest pressure*
$P_{tnet\_max} := P_{Hydro\_max} - P_{ex}$	$P_{tnet\_max} = 7218psig$	*_maximum internal net test pressure*
$SH := \frac{P_{tnet\_max}\cdot D}{2\cdot t}$	$SH = 27ksi$	*_hoop stress, based on thin wall OD*
$\%SMYS := \frac{SH}{Y}$	$\%SMYS = 41\%$	
$CheckSH := if(\%SMYS < 95\%, "OK", "Not OK")$		$CheckSH = "OK"$

2. Offshore Hydrostatic Test Pressure and MAOP

The required hydrostatic test (hydrotest) pressure is 1.25 of the top SITP. The local test pressure should not be less than 1.25 of the local SITP. The effective hydrotest pressure is the net pressure the pipe experiences. For internal carrier pipe not subjected to hydrostatic pressure, the effective test pressure is the same as the hydrotest internal pressure. The Maximum Allowable Operating Pressure (MAOP) is the lowest of: a) Pipe Design pressure; b) 80% of Minimum Hydrotest Pressure and c) Minimum Design Pressure for Valves, Flanges, Fittings or other Components where applicable.

Effective Hydrotest Net Pressure

$P_{tnet} := P_{Hydro} - P_{ex}$	$P_{tnet} = 7018psig$	*_minimum hydrotest net pressure*
$P_{eff} := P_{tnet}$	$P_{eff} = 7018psig$	*_effective test pressure*
$P_{req} := 1.25\cdot P_{sitp1} - P_{ex}$	$P_{req} = 5392psig$	*_required local net test pressure*
$CheckP_{eff} := if(P_{eff} \ge P_{req}, "OK", "Not OK")$		$CheckP_{eff} = "OK"$

MAOP

$MAOP_{hydro} := 0.80\cdot P_{eff} + P_{ex}$		*_MAOP based on hydrotest pressure*
$MAOP_{hydro} = 8347psig$		
$P_{fittingH} := P_{fitting} + \gamma\cdot \lvert H_{local}\rvert$	$P_{fittingH} = 9383psig$	*_minimum design pressure for the components on sled at sled water depth*
$MAOP := min(MAOP_{hydro}, P_i, P_{fittingH})$		*_MAOP at the calculation location*
$MAOP = 8347psig$		
$CheckMAOP := if(MAOP \ge P_{sitp1}, "OK", "Not OK")$		$CheckMAOP = "OK"$

Calculation 8. N3 Sled 10" Pipe Spool Pressure Design (1/3)

(All Pressures are gauge Pressures)

Constants

Sea Water Specific Weight $\gamma \equiv 64 \cdot \mathrm{lbf} \cdot \mathrm{ft}^{-3}$

Modulus of Elasticity of Steel $E \equiv 29000\,\mathrm{ksi}$

Design Data

Outside Diameter for Pipe	$D = 10.75\mathrm{in}$
Pipe Wall Thickness	$t = 0.875\mathrm{in}$
SMYS of Pipe	$Y = 70\mathrm{ksi}$
Water Depth at Well with the Maximum SITP	$H_{A4} = -6150\mathrm{ft}$
Mean Sea Level Elevation (MSL)	$H_{msl} = 0\,\mathrm{ft}$
Elevation at the Riser Top	$H_{top} = 67\,\mathrm{ft}$
Water Depth at Calculation Location	$H_{local} = -6150\mathrm{ft}$
Maximum SITP of the Flowline Loop, at Well A-4	$P_{sitp} = 6500\mathrm{psig}$
Maxiumu SITP at Mean Sea Level Elevation	$P_{msl} = 5600\mathrm{psig}$
Minimum Design Pressure of Sled Components	$P_{fitting} = 6650\mathrm{psig}$
Construction Design Factor (B31.8) (Line Pipe)	$F = 0.72$
Longitudinal Joint Factor (DSAW or Seamless Pipe)	$f_e = 1$
Temperature Derating Factor (B31.8, Temp. <=250 F)	$f_t = 1$

Calculation 8. N3 Sled 10" Pipe Spool Pressure Design (2/3)

1. Internal Pressure Design

Local SITP Calculation

$P_{gradient} := \frac{P_{sitp} - P_{msl}}{H_{A4} - H_{msl}}$ $P_{gradient} = -0.146ft^{-1}\,psig$ _*pressure gradient assumption*

$P_{sitp1} := P_{sitp} - P_{gradient} \cdot (H_{A4} - H_{local})$ $P_{sitp1} = 6500psig$ _*SITP at calculation location*

$P_{top} := P_{sitp} - P_{gradient} \cdot (H_{A4} - H_{top})$ $P_{top} = 5590psig$ _*SITP at riser top of +67 ft elevation*

Internal Design Pressure (B31.8)

The sled piping is exposed to external pressure.

$P_{ex} := \gamma \cdot |H_{local}|$ $P_{ex} = 2733psig$ _*external pressure*

$P_i := P_{ex} + \frac{(2 \cdot Y \cdot t \cdot f_e \cdot F \cdot f_t)}{D}$ $P_i = 10938psig$ _*internal design pressure B31.8*

$CheckP_{i1} := if(P_i > P_{sitp1}, "OK", "Not OK")$ $CheckP_{i1} = "OK"$

Hoop Stress during Hydrotest

The onshore hydrotest pressure for all the NaKika North Sleds is 8,300 to 8,350 psig based on approximately 1.25 times the minimum design pressure of the sled components. The required offshore hydrotest pressure is 1.25 times the SITP at riser top (+67ft). The Hoop Stress during hydrotest due to maximuminternal net pressure should not exceed 95% of SMYS.

A. Onshore Test

$P_{Hydro} := 8350psig$ _*maximum allowable hydrotest pressure on Sled*

$P_{tnet} := P_{Hydro}$ $P_{tnet} = 8350psig$ _*internal net pressure*

$SH := \frac{P_{tnet} \cdot D}{2 \cdot t}$ $SH = 51ksi$ _*hoop stress, based on thin wall OD*

$\%SMYS := \frac{SH}{Y}$ $\%SMYS = 73\%$

$CheckSH := if(\%SMYS < 95\%, "OK", "Not OK")$ $CheckSH = "OK"$

Calculation 8. N3 Sled 10" Pipe Spool Pressure Design (3/3)

B. Offshore Test

$P_{ex} = 2733\text{psig}$		*_external pressure*
$P_{fluid} := (H_{top} - H_{local}) \cdot \gamma$	$P_{fluid} = 2763\text{psig}$	*_testing water head pressure*
$P_{Hydro} := 1.25 \cdot P_{top} + P_{fluid}$	$P_{Hydro} = 9751\text{psig}$	*_local minimum hydrotest pressure*
$P_{Hydro\_max} := P_{Hydro} + 200 \cdot \text{psig}$	$P_{Hydro\_max} = 9951\text{psig}$	*_maximum hydrotest pressure*
$P_{tnet\_max} := P_{Hydro\_max} - P_{ex}$	$P_{tnet\_max} = 7218\text{psig}$	*_maximum internal net test pressure*
$SH := \dfrac{P_{tnet\_max} \cdot D}{2 \cdot t}$	$SH = 44\text{ksi}$	*_hoop stress, based on thin wall OD*
$\%SMYS := \dfrac{SH}{Y}$	$\%SMYS = 63\%$	
CheckSH := if(%SMYS < 95%, "OK" , "Not OK")		CheckSH = "OK"

2. Offshore Hydrostatic Test Pressure and MAOP

The required hydrostatic test (hydrotest) pressure is 1.25 of the top SITP. The local test pressure should not be less than 1.25 of the local SITP. The effective hydrotest pressure is the net pressure the pipe experiences. For internal carrier pipe not subjected to hydrostatic pressure, the effective test pressure is the same as the hydrotest internal pressure. The Maximum Allowable Operating Pressure (MAOP) is the lowest of: a) Pipe Design pressure; b) 80% of Minimum Hydrotest Pressure and c) Minimum Design Pressure for Valves, Flanges, Fittings or other Components where applicable.

Effective Hydrotest Net Pressure

$P_{tnet} := P_{Hydro} - P_{ex}$	$P_{tnet} = 7018\text{psig}$	*_minimum hydrotest net pressure*
$P_{eff} := P_{tnet}$	$P_{eff} = 7018\text{psig}$	*_effective test pressure*
$P_{req} := 1.25 \cdot P_{sitp1} - P_{ex}$	$P_{req} = 5392\text{psig}$	*_required local net test pressure*
$CheckP_{eff} := \text{if}(P_{eff} \geq P_{req}, \text{"OK"}, \text{"Not OK"})$		$CheckP_{eff} = \text{"OK"}$

MAOP

$MAOP_{hydro} := 0.80 \cdot P_{eff} + P_{ex}$		*_MAOP based on hydrotest pressure*
$MAOP_{hydro} = 8347\text{psig}$		
$P_{fittingH} := P_{fitting} + \gamma \cdot \lvert H_{local} \rvert$	$P_{fittingH} = 9383\text{psig}$	*_minimum design pressure for the components on sled at sled water depth*
$MAOP := \min(MAOP_{hydro}, P_i, P_{fittingH})$		*_MAOP at the calculation location*
$MAOP = 8347\text{psig}$		
$CheckMAOP := \text{if}(MAOP \geq P_{sitp1}, \text{"OK"}, \text{"Not OK"})$		CheckMAOP = "OK"

G24244
SN: 13827 +
13828

In Reply Refer To: MS 5232

03 JUL 2002

Mr. Craig W. Dickerson
Shell Offshore Inc.
Two Shell Plaza
Post Office Box 2648
Houston, Texas 77252-2648

Dear Mr. Dickerson:

Reference is made to the following application that has been reviewed by the Minerals Management Service:

Application Type: New Right-of-Way Pipeline
Application Date: April 23, 2002

Work Description: Create 200-foot wide right-of-way and install, operate, and maintain the following:

One 10-inch by 16-inch pipe-in-pipe, 6.87 miles long, to transport bulk oil from Kepler Well K-1, Sled N2 in Block 383, Lease OCS-G 07937, through Blocks 384, 385, to Ariel Well A-4, Sled N3 located in Block 429, Lease OCS-G 07944, all of which is located in the Mississippi Canyon area.

Assigned Right-of-Way Number: OCS-G 24244
Assigned Segment Number: 13827
Outer Casing Number: 13828

Pursuant to 43 U.S.C. 1334(e) and 30 CFR 250.1000(d), your application is hereby approved.

The approval is subject to the following:

Our review indicates that the routes to be taken by boats and aircraft in support of your proposed activities are located in or could traverse Military Warning Area W-453. Therefore, please be advised that you will contact the Air National Guard-CRTC, Gulfport/ACTS, Gulfport, Mississippi 39507 [contact TSgt. D. Crawford or TSgt. L. Wyche at (228) 867-2433] concerning the control of electromagnetic emissions and use of boats and aircraft in Military Warning Area W-453.

Your request to use navigational positioning equipment to comply with Notice to Lessees and Operators No. 98-20, Section IV.B, is hereby approved.

Assigned MAOP (psi): 5,590
MAOP Determination: Subsea Segment No. 13831, Hydrostatic Test Pressure of Pipeline.

Please be reminded that, in accordance with 30 CFR 250.1008(a), you must notify the Regional Supervisor at least 48 hours prior to commencing the installation or relocation of a pipeline or conducting a pressure test on the pipeline. Also, in accordance with 30 CFR 250.1008(b), you must submit a report to the Regional Supervisor within 90 days after completion of any pipeline construction.

Sincerely,

(Org.Sgd.) J. R. Hennessey

Donald C. Howard
Regional Supervisor
Field Operations

bcc: 1502-01 Segment No. 13827, ROW OCS-G 24244 (MS 5232)
1502-01 ROW OCS-G 24244 (Microfilm) (MS 5033)
1502-01 Segment No. 13828, ROW OCS-G 24244 (MS 5232)
/ 1502-01 ROW OCS-G 24244 (Microfilm) (MS 5033)
MS 5250 New Orleans District w/flow schematic
MS 5232 Cartography

TMeyer:amm:07/03/02:Shell Offshore Inc.-13827

MMS PERMIT APPLICATION
NaKika North Oil Flowline Permit #5: Kepler Well K-1 to Ariel Well A-4 and Umbilicals

FLOWLINE DESIGN SUMMARY

NaKIKA NORTH FIELDS (Kepler and Ariel):
PIPE-IN-PIPE FLOWLINE LOOP;
ELECTRIC, HYDRAULIC AND
CHEMICAL INJECTION UMBILICALS

Mississippi Canyon Block 383
to
Mississippi Canyon Block 474 (NaKika Host)

Prepared by
Shell International Exploration and Production, Inc. (SIEP) for

Shell Offshore, Inc.

March 2002

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I. INTRODUCTION - NaKIKA FIELD DEVELOPMENT

The NaKika Field is located some 144 miles southeast of New Orleans, Louisiana in water depths ranging from 5,800 feet to 7,000 feet. The field is composed of five independent, sub-economic fields that were discovered between 1987 and 1997. The five fields: Kepler (MC-383), Ariel (MC-429), Fourier and Herschel (MC-522), and East Anstey (MC-607) will be co-developed via subsea tiebacks to the centrally located NaKika host facility at MC-474 for fluids processing and export via pipelines. Kepler, Ariel, and Herschel fields are predominately oil while Fourier and East Anstey fields are predominately gas. An overview of the Na KIKA Field Arrangement is shown in Figure 1.

The Ariel and Kepler fields are in the NaKika north field. There are total five wells with three dispersed wells at Ariel and two clustered wells at Kepler. The general field arrangement of NaKika North Field is illustrated in Figure 2 and has the following features:

- A total of 5 (five) segments of 10-inch x 16-inch electrical heated Pipe-In-Pipe (PIP) flowlines are used to transport the oil by forming a single "piggable" loop interconnecting all five wells. The flowlines terminate at the NaKika host as two catenary risers using flexible-joint fittings. The flowlines and risers are approximately 25.3 miles in length and in water depths ranging from 5800' to 6350'.
- Each production riser also has a dedicated gas-lift sled and gas lift riser to improve production rates, reservoir recovery, and flow stability (slug suppression).
- Five umbilicals having metal tubes and electric conductors provide hydraulic power, annulus vent, electrical service, and chemical injection to the Ariel/Kepler subsea system.

The schedule for installation of the North field pipelines is as the following:

Table 1. North Flowline and Riser Installation Schedule

Description	Scheduled Data	Installation Method
Flowlines	August 2002	J-Lay by Coflexip Stena Offshore
Risers	April 2003	J-Lay by Coflexip Stena Offshore
Gas Lift Risers	May 2003	Reel-Lay by Coflexip Stena Offshore
Umbilicals	March – May, 2003	Reel-Lay by Halliburton Subsea

The flowlines will be installed by the J-Lay method by Coflexip Stena Offshore Limited using their dynamically positioned pipelay barge Deep Blue. The umbilicals will be installed by Halliburton Subsea using their lay vessel Toisia Perseus. There are <u>no</u> third party pipeline crossings along the proposed route of north flowline loop.

A deep tow survey of the proposed route for each flowline was conducted in August 2001. The results of the survey are presented in a geotechnical assessment report prepared by Geomatrix Consultants, Inc. dated November 2001 entitled "Geologic Assessment for Proposed Flowlines Area North, Mississippi Canyon 383 to 474, Nakika Pipeline Project, Northern Gulf of Mexico"

1. *Survey Synopsis*

As assessed in the *Geologic Assessment for Proposed Flowlines Area South Mississippi Canyon 383 to 474 Nakika Pipeline Project – Northern Gulf of Mexico* produced by Geomatrix in January of 2002, the deeptow data shows no evidence of hard-bottom conditions, seafloor faulting, fluid expulsion features, or any other potential geologic or archeological hazard along the intrafield flowline or umbilical routes.

While some faults associated with fluid expulsions areas were identified in MC-476, MC-477, MC-520, & MC-521, the intrafield flowlines and umbilicals avoid these areas completely. No faults or fluid expulsion areas were identified within 3,000 ft of the proposed intrafield flowline or umbilical routes and there is no evidence to show than any chemosynthetic communities exist along any of the proposed routes. There is a small mudflow area to the Northwest of the Kepler wells; however, this does not pose a risk to the North intrafield flowline and umbilicals.

There are no obstructions or man-made structures along the routes. Some man made features (i.e. Drilling mud splays) occur along the routes, but do not present a hazard to installation or operations of the intrafield flowlines or umbilicals.

As concluded in the above report, "There is no evidence for adverse geologic conditions, obstructions, chemosynthetic communities, or cultural features either on the seafloor or at depth along any of the proposed routes that would preclude the routing of an intrafield flowline or umbilical."

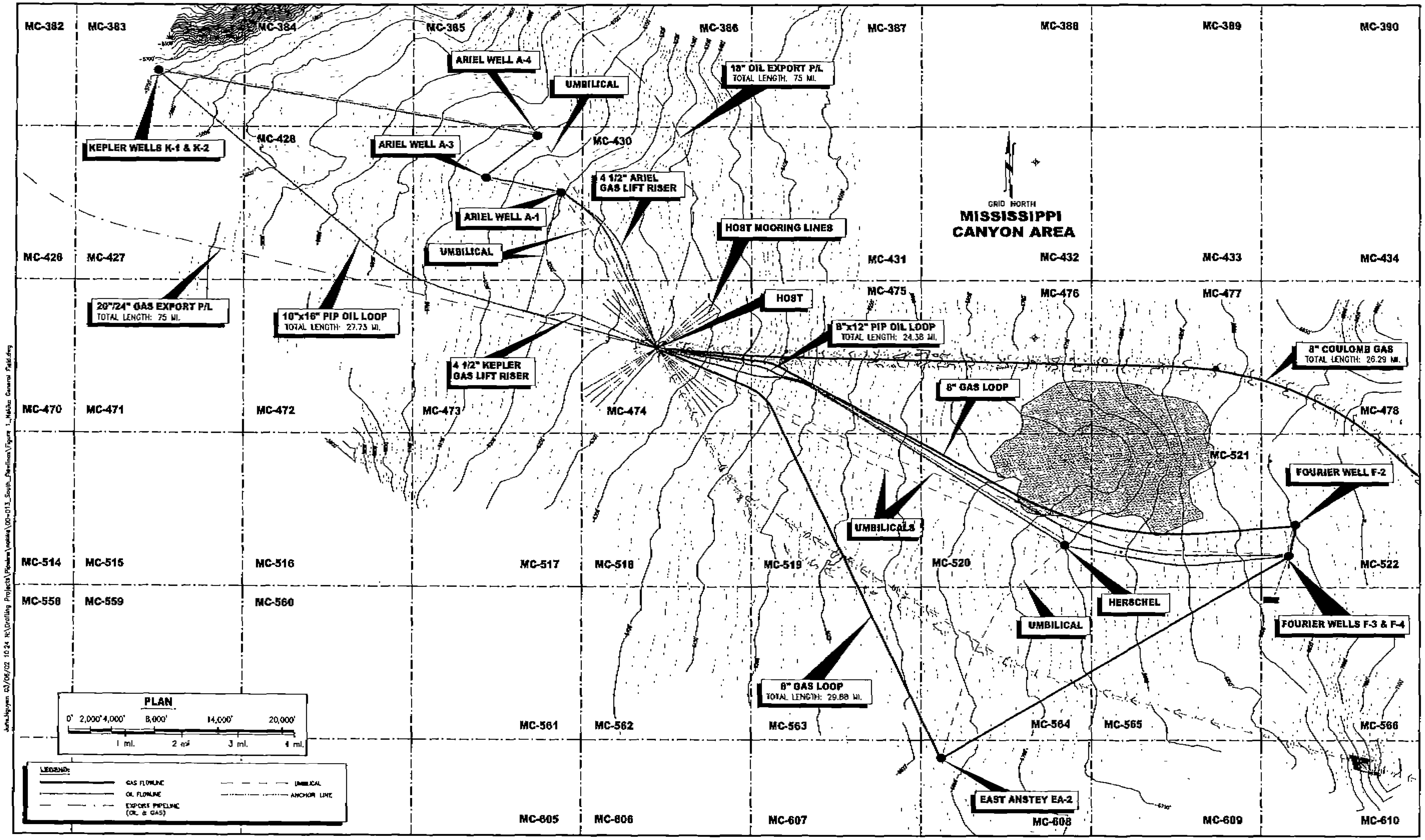

Figure 1. NaKiKa General Field Arrangement

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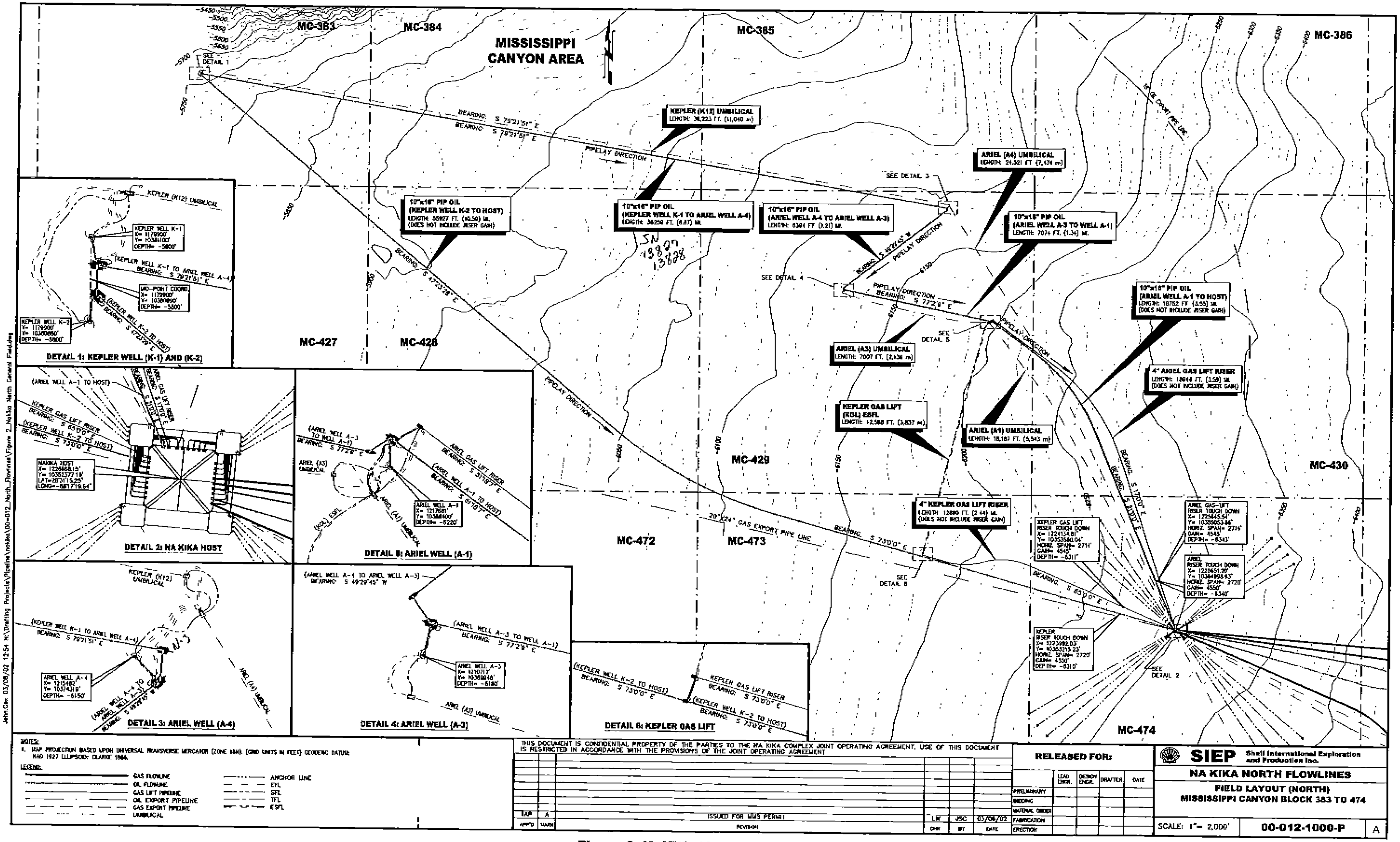

Figure 2. NaKIKa North General Field Arrangement

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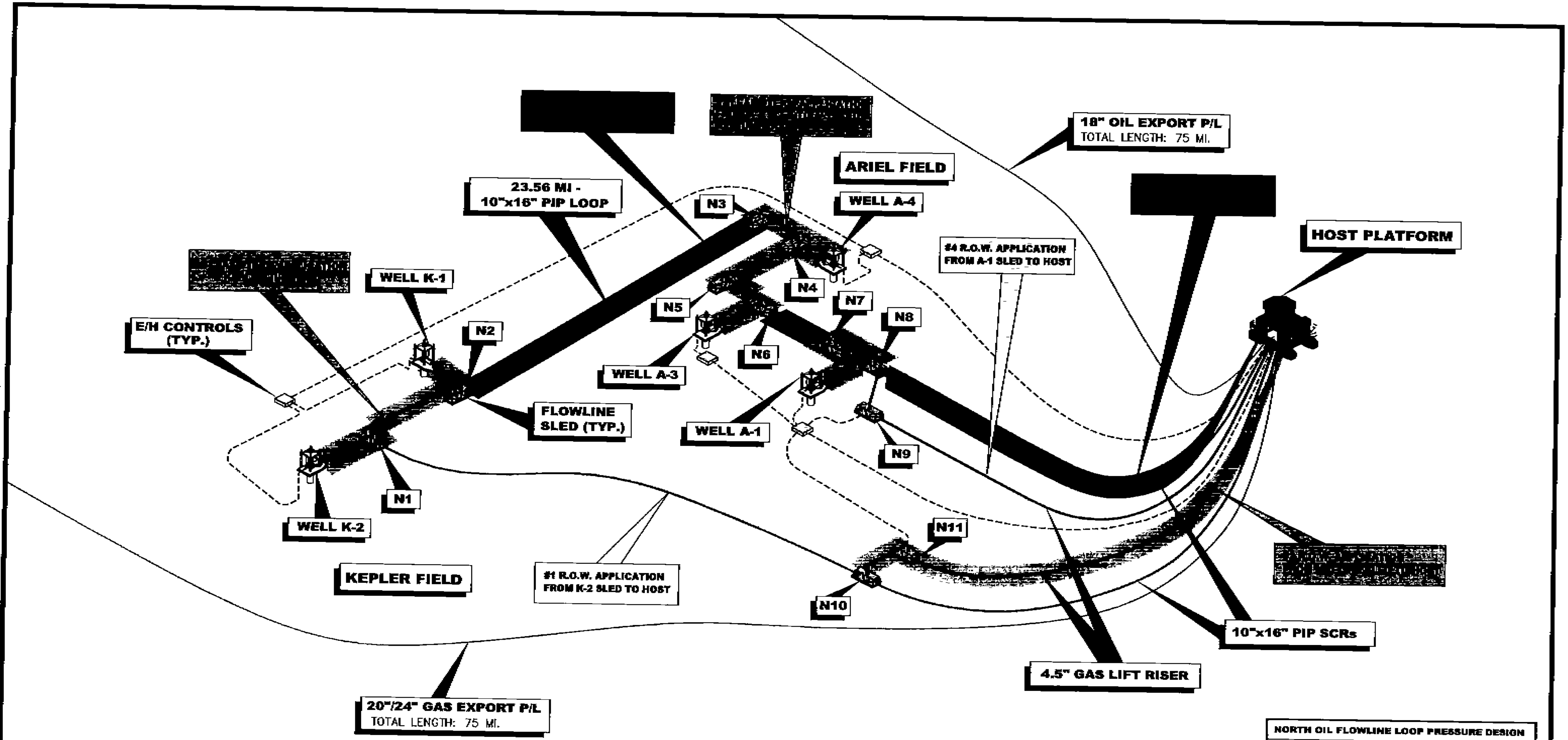
Figure 3. North Oil Flowline and Umbilical "Color Coded" Schematic (Drawing 00-12-1200)



NOTE

1. DESIGN PRESSURE FOR THE ENTIRE LOOP IS BASED ON ARIEL A-4 (GAS) MAXIMUM PRESSURE.

LEGEND

- - - - - - - - UMBILICAL
———— OIL
———— GAS

NORTH OIL FLOWLINE LOOP PRESSURE DESIGN		
WELL	WELL SITP (psig)	SURFACE SITP (psig)
KEPLER K-1	5,000	4,100
ARIEL A-1	5,300	3,800
ARIEL A-3	5,600	4,000
ARIEL A-4 (OIL)	5,500	3,900
ARIEL A-4 (GAS)	6,500	5,600

NO.	DATE	REVISION	BY	APP.
A	03/07/02	ISSUED FOR MMS PERMIT APPLICATION	DN	TAP

NAKIKA NORTH FLOWLINES

SIEP Shell International Exploration and Production Inc.

OVERALL FIELD LAYOUT
10"x16" PIP OIL FLOWLINE LOOP
COLOR CODE FOR PERMIT APPLICATIONS

SCALE	NONE	DATE	REF.	REV.
DRAWN	DN	02/02	00-012-1200	A

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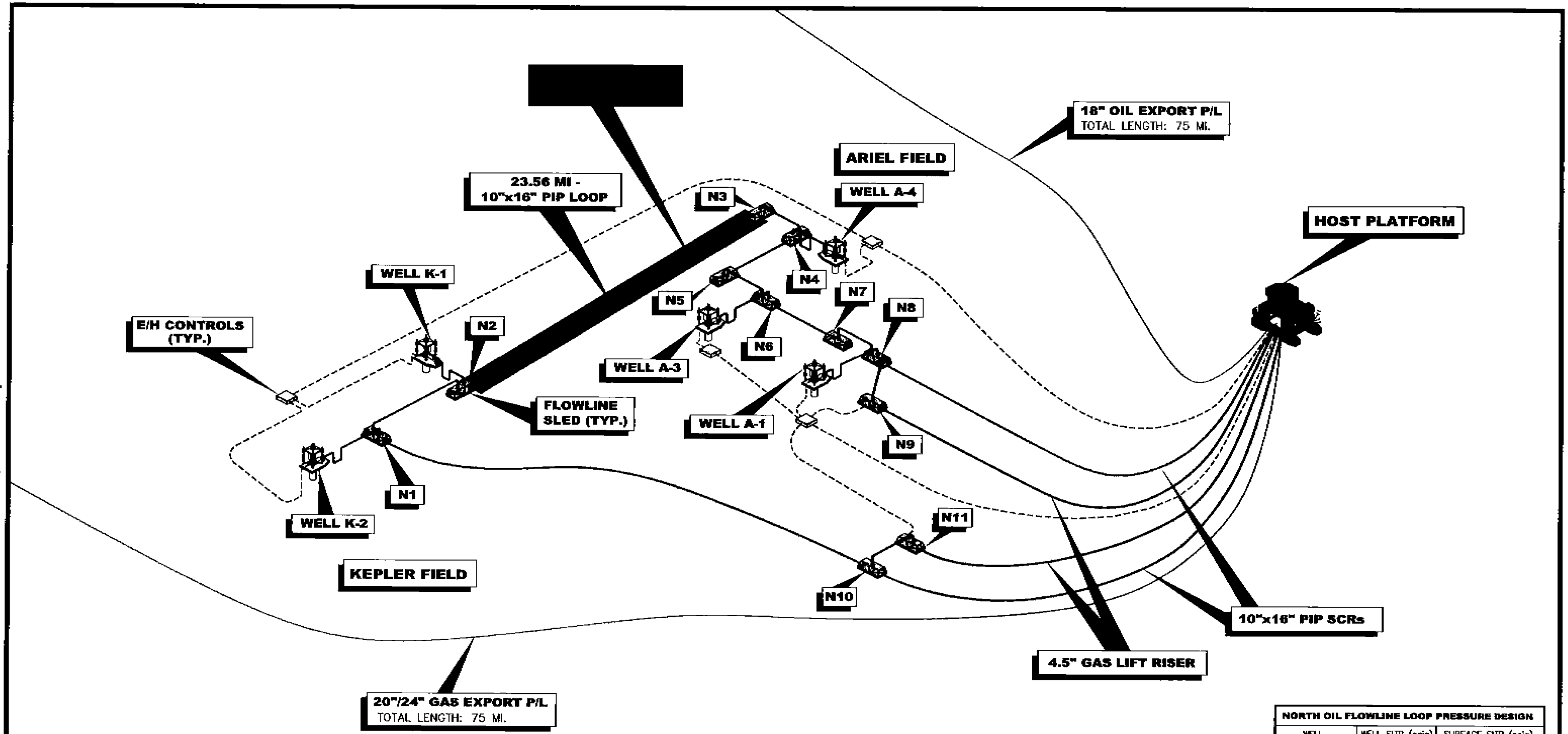
Figure 4. "Color Coded" Pipe Segments for North Oil Flowline Loop Permit #5 (Drawing 00-12-1205)



NOTE

1. DESIGN PRESSURE FOR THE ENTIRE LOOP IS BASED ON ARIEL A-4 (GAS) MAXIMUM PRESSURE

LEGEND

- - - - - - UMBILICAL
———— OIL
———— GAS

NORTH OIL FLOWLINE LOOP PRESSURE DESIGN

WELL	WELL SITP (psig)	SURFACE SITP (psig)
KEPLER K-1	5,000	4,100
ARIEL A-1	5,300	3,800
ARIEL A-3	5,600	4,000
ARIEL A-4 (OIL)	5,500	3,900
ARIEL A-4 (GAS)	6,500	5,600

NO.	DATE	REVISION	BY	APP.
A	03/07/02	ISSUED FOR MMS PERMIT APPLICATION	DN	TAP

NAKIKA NORTH FLOWLINES

SIEP Shell International Exploration and Production Inc.

10"x16" PIP OIL FLOWLINE LOOP ILLUSTRATION OF PIPE SEGMENT FOR #5 PERMIT APPLICATION

SCALE	NONE	DATE	REF.	REV.
DRAWN	DN	03/02	00-012-1205	A

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2. *Permit Applications*

Because of the complexity of the Nakika North Oil flowline loop, individual permit applications are prepared for different flowline segments, jumpers and risers as illustrated in Figure 4 with different colors to indicate different permit applications. Detailed pipe descriptions to be included in each permit application are listed in Table 2. This document is for the pipe segment from the Kepler Well K-1 sled to the Ariel Well A-4 sled, permit application document #5, as highlighted in Table 2 and illustrated in Figure 4. The plat maps for this flowline segment are included in Attachment 1.

Table 2. Permit Application Documents for NaKika North Oil Flowline Loop, 10"x16" PIP System

Permit Number	Pipe Segment Description	Type of Permit
#1	From Kepler Well K-2 Sled N1 to Host: • Midline Sled 5" Pipe: 5.5625" x 0.750", API 5L, X65, Seamless • Midline Sled 10" Carrier Pipe: 10.750" x 0.875", API 5L, X70, Seamless • Flowline PIP - Carrier: 10.750" x 0.812", API 5L, X70, Seamless • Flowline PIP - Casing: 16.000" x 0.750", API 5L, X70, DSAW • Riser PIP - Carrier: 10.750" x 0.875", API 5L, X70, Seamless • Riser PIP - Casing: 16.000" x 0.750", API 5L, X70, DSAW • FPS Hull Piping: 10.750" x 0.875", API 5L, X70, Seamless • Kepler, Static Umbilical System K12 • Kepler Gas Lift, Static Umbilical System KGL	Right of Way
#2	Kepler Gas Lift Riser from Midline Sled N10 to Gas Lift Sled N11 to Host: • Sled 5" Pipe: 5.5625" x 0.750", API 5L, X65, Seamless • Gas Lift Jumper: 5.94" x 0.939", 410, Stainless Steel • Gas Lift Riser Pipe: 4.500" x 0.674", API 5L, X65, Seamless • Stress-Joint Pipe: Tapered from 4.594" x 0.0.761" to 9.352" x 3.14" at the flange • Hull Piping above Flange: 6.625" s 0.875", API 5L, X65, Seamless • Kepler Gas Lift, Static Umbilical System KGL	Right Of Way
#3	From Ariel Well A-3 Sled N6 to A-1 Sled N7 and from N8 to Host: • Sled 5" Pipe: 5.5625" x 0.750", API 5L, X65, Seamless • Sled 10" Carrier Pipe: 10.750" x 0.875", API 5L, X70, Seamless • Flowline PIP - Carrier: 10.750" x 0.812", API 5L, X70, Seamless • Flowline PIP - Casing: 16.000" x 0.750", API 5L, X70, DSAW • Riser PIP - Carrier: 10.750" x 0.875", API 5L, X70, Seamless • Riser PIP - Casing: 16.000" x 0.750", API 5L, X70, DSAW • FPS Hull Piping: 10.750" x 0.875", API 5L, X70, Seamless • Ariel 3, Static Umbilical System A3 • Ariel 1, Static Umbilical System A1	Right of Way
#4	Ariel Gas Lift Riser from A-1 Sled N8 to Gas Lift Sled N9 to Host: • Sled 5" Pipe: 5.5625" x 0.750", API 5L, X65, Seamless • Gas Lift Jumper: 5.94" x 0.939", 410, Stainless Steel • Gas Lift Riser Pipe: 4.500" x 0.674", API 5L, X65, Seamless • Stress-Joint Pipe: Tapered from 4.594" x 0.0.761" to 9.352" x 3.14" at the flange • Hull Piping above Flange: 6.625" s 0.875", API 5L, X65, Seamless • Ariel 1, Static Umbilical System A1	Right Of Way

(Table 2. Continued)

Permit Number	Pipe Segment Description	Type of Permit
#5	From Kepler Well K-1 Sled N2 to Ariel Well A-4 Sled N3: • Sled 5" Pipe: 5.5625" x 0.750", API 5L, X65, Seamless • Sled 10" Carrier Pipe: 10.750" x 0.875", API 5L, X70, Seamless • Flowline PIP - Carrier: 10.750" x 0.812", API 5L, X70, Seamless • Flowline PIP - Casing: 16.000" x 0.750", API 5L, X70, DSAW • Kepler Gas Lift, Static Umbilical System KGL	Right Of Way
#6	Three Kepler Jumpers: • Well K-2 Jumper: 5.94" x 0.939", 410, Stainless Steel • Well K-1 Jumper: 5.94" x 0.939", 410, Stainless Steel • Flowline Jumper from K-2 Sled N1 to K-1 Sled N2: 10.750" x 0.875", API 5L, X70, Seamless • Kepler Gas Lift, Static Umbilical System KGL	Lease Term
#7	From Ariel Well A-4 Sled N4 to A-3 Sled N5 and 6 Jumpers: • Flowline Jumper from N3 to N4: 10.750" x 0.875", API 5L, X70, Seamless • Well A-4 Jumper: 5.94" x 0.939", 410, Stainless Steel • Flowline PIP - Carrier: 10.750" x 0.812", API 5L, X70, Seamless • Flowline PIP - Casing: 16.000" x 0.750", API 5L, X70, DSAW • Flowline Jumper from N5 to N6: 10.750" x 0.875", X70 • Well A-3 Jumper: 5.94" x 0.939", 410, Stainless Steel • Well A-1 Jumper: 5.94" x 0.939", 410, Stainless Steel • Ariel 4, Static Umbilical System A4 • Ariel 3, Static Umbilical System A3	Lease Term

3. *Well and Surface SITP*

The maximum design shut-in tubing pressure (SITP) for the North field, five (5) wells, is 6,500 psig at the wellhead and 5,600 psig at 0 feet MSL of the riser top. This SITP is for well A-4, which will commingle production from the K-1, A-1, A-3 and A-4 zones. The other wells SITPs are less than these maximum values. For information and comparison the individual well SITPs are listed in Table 3. The flowline and riser design temperature is -20°F to 250°F. The produced fluid operating temperature ranges for the flowline and riser are 40°F to 110°F.

The maximum SITP for the gas lift riser at the seabed will be the SITP at the midline sled, which is calculated based on the maximum SITP of 6,500 psig at well A-4 and the maximum SITP of 5,600 psig at 0 feet MSL of the riser top. A linear pressure gradient is used to calculate local SITP along the flowline loop. The maximum SITP at the gas lift riser top is assumed the same as the flowline of 5,600 psig during shut-in condition.

Table 3. Calculated Well and Surface SITP

Well	Maximum Well SITP Psig	SITP at 0 ft MSL of Riser Top (psig)	Water Depth at Well Site (feet, MSL)	Comments and Notes
Kepler1 (K-1) Oil	5,000	4,100	-5,800	Maximum values at the seafloor/top of riser produced on its own
Kepler 2 (K-2) Oil	N/A	N/A	-5,800	Not available
Ariel 1 (A-1) Oil	5,300	3,800	-6,250	Maximum values at the seafloor/top of riser. Assumes A-1 produced on its own
Ariel 3 (A-3) Oil	5,600	4,000	-6,150	Maximum values at the seafloor/top of riser. Assumes A-3 produced on its own
Ariel 4 (A-4) Oil*	5,500	3,900	-6,150	Maximum values at the seafloor/top of riser. Assumes A-4 Oil produced on its own.
Ariel 4 (A-4) Gas*	6,500	5,600	-6,150	Maximum values at the seafloor/top of riser. Assumes A-4 gas produced on its own.

Note: *It is uncertain whether Ariel Well A-4 is gas or oil well. The maximum SITP of a gas well is used for pipeline design.

4. *Flowline Design Approach*

The pipe design pressure and subsequent pipe wall thickness requirements are based on the design equation as required in 30CFR250 Subpart J. All the flowline segments of the North loop are designed based on the maximum SITP at Ariel gas wellhead of 6,500 psig. The maximum SITP of 5,600 psig at 0 feet MSL of the riser top is used. The gas lift riser design pressure is based on the local SITP at the midline sled in the flowline. In addition and when applicable, the effects of external pressure in the design are considered. These design calculations and related considerations are presented in Section II of this permit application document.

5. *Flowline Jumper and Well Jumper Design*

In addition to the flowlines, design considerations of the short sections of pipe connecting flowline "sled" to flowline "sled" (flowline jumper) and wellhead to flowline "sled" (well jumpers) are presented in those permits where jumpers are considered (see Table 2).

II. FLOWLINE DESIGN

The NaKika North Flowline Loop system is designed to transport produced well fluids from the five wells in the NaKika north field located Mississippi Canyon Block 383 (MC-383), MC-429 to NaKika host located in Mississippi Canyon Block 474 (MC-474) as illustrated in Figure.1. The flowline pressure piping is designed to contain the maximum full well A4 pressure of 6,500 psig. The flowlines are a pipe-in-pipe (PIP) system and thermally insulated to ensure normal operation above the hydrate formation temperature of the commodity and, in addition, to maintain temperatures above the hydrate formation temperature for the longest practical time during flow interruptions. In addition, the flowlines are electrically heated as a remediation tool that can be used to mitigate hydrate problems. The flowline is piggable with a scraper launcher and receiver located on the NaKika Host platform (FPS).

The NaKika North flowlines traverse elevations from –6,340 feet MSL to +67 feet MSL for a total elevation change of 6,407 feet. The design includes consideration of both elevation changes and internal fluid hydrostatics (i.e. density, etc.). Each of the flowline risers are terminated with pipe-in-pipe Steel Catenary Riser Flex Joints with a maximum operation pressure (MAOP) of 5,600 psig at –70 feet MSL elevation.

For the PIP segments of the system, external pressure is 0 psig for the carrier pipe. For other items that compose the system, such as the sled piping and jumpers that are not PIP, the localized external pressure is considered as part of the design. For clarity and consistency all pressure calculations illustrated herein utilize *Gauge pressure (psig)*. External hydrostatic pressure is consistently applied throughout the calculations.

Glossary of Main Terms:

- **Carrier pipe** The pressure containing inside pipe of the insulated pipe-in-pipe system.
- **Casing pipe** The water exclusion outside pipe of the insulated pipe-in-pipe system.
- **psig** Gauge pressure, pounds-per-square-inch at sea level conditions.
- **MSL** Mean Sea Level Elevation Datum
- **VIV** Vortex Induced Vibration
- **SITP** Shut-in Tubing Pressure
- **PIP** Pipe-In-Pipe
- **MAOP** Maximum Allowable Operating Pressure
- **FBE** Fusion Bonded Epoxy
- **TLPE** Triple Layer Polyethylene
- **SCR** Steel Catenary Riser

1. *Commodity To Be Transported*

Available reservoir fluid compositions for the Ariel reservoirs are summarized in Table 4. These compositions are based on bottomhole fluid samples collected from the Ariel Wells A-1 and A-2. The assumptions for the Kepler field used in the design are presented in Table 5.

Table 4. NaKika North Oil Field Ariel Produced Fluid Composition

Contents	Ariel #1 (Well A-1)	Ariel #4 (Well A-4)
Water Depth (ft.)	6,250 ft	6,150 ft
Expected Hydrocarbon	Oil	Oil or Gas
API Gravity (degree API @ 60 °F)	28	28
Gas SG Relative to Air	.63	.63
Early Life GOR- (scf/bbl)	1,000	1,000
Late Life GOR- (scf/bbl)	3,000	3,000
Bubble/Dew Point – (psi)	7,116-7,360	7,116-7,360
H2S – (%)	nil	nil
CO_2 – (mol %)	0.1	0.1
Sand Production	nil	nil
Life – (years max)	20	20
Artificial Lift	Gas lift riser	Gas lift riser

Table 5. NaKika North Oil Field Kepler Produced Fluid Composition

Description	Kepler #2 (Well K-1)	Kepler #3 (Well K-2)
Water Depth (ft.)	5,800 ft	5,800 ft
Expected Hydrocarbon	Oil	Oil
API Gravity (degree API @ 60 °F)	28	28
Gas SG relative to air	0.7	0.7
Early Life GOR- (scf/bbl)	950	950
Late Life GOR- (scf/bbl)	1,400	1,400
Bubble/Dew Point – (psi)	5,400	5,400
H2S – (%)	nil	nil
CO_2 – (mol %)	0.1	0.1
Sand production	nil	nil
Life – (years max)	20	20
Artificial Lift	Gas lift riser	Gas lift riser

2. *Pipe-In-Pipe (P-I-P) Flowline Segment, Riser Specifications and Weight*

The NaKika North Flowline Loop is formed by five 16" x 10" PIP flowline segments connecting the five wells. As listed in Table 2, the pipe segments considered in the permit application are from the K-1 first end sled (N2) to the A-4 second end sled (N3). The total length of this pipe segment is 36,259 feet. The properties of the each PIP section are listed in Table 6.

The Specific Gravity is calculated as:

Weight in Air (empty) / Water Displacement in Sea Water

Seawater specific weight of 64 lb/ft^3 is used.

Table 6. Pipe Properties for Flowline Segment from K-1 to A-4

Parameter	5" Sled Pipe	10" Sled Pipe	Flowline
Length (feet)	~15	~20	36,259
Pipe System	Single pipe	Single pipe	PIP
Carrier Pipe: OD x WT, Grade	5.5625"x0.750", X65, Seamless	10.750"x0.875", X70, Seamless	10.750"x0.812", X70, Seamless
Casing Pipe: OD x WT, Grade	N/A	N/A	16.000"x0.750", X70, DSAW
Pipe Specification	API-5L	API-5L	API-5L
External Coating (mil)	Painted	FBE 8-10	FBE Casing 16-18 Carrier 8-10
Internal Coating (mil)	N/A	N/A	Copon 2306 WB On Casing Pipe Only 2-3
Insulation Material[1]	C-Therm FPP	C-Therm FPP	PUF & PEJ
Min. Insulation Thickness (in)	3	3	1.535 PUF & 0.080 PEJ
Empty Weight in Air, lb/ft	62.98	131.55	212.54
Water Displacement, lb/ft	46.96	98.17	89.76
Empty Weight in Water, lb/ft	18.84	37.67	122.78
SG (empty, seawater=1)	1.40	1.38	2.37
Product Filled Weight in Air[2], lb/ft	68.08	156.60	238.29
Product Filled Weight in Water[2], lb/ft	23.94	62.72	148.53
Product Filled SG[2]	1.51	1.64	2.66
Hoop Stress Factor	0.72	0.72	0.72

Notes:

1. PUF = Polyurethane Foam, density of 4 lb/ft^3
   PEJ= Polyethylene Jacket, density of 56 lb/ft^3
   C-Therm FPP = Cummings C-Therm Pour-In-Place, density of 43 lb/ft^3 dry and 48 lb/ft^3 wet
2. Based on crude oil density of 56.7 lb/ft^3.

3. *Cathodic Protection*

<u>Pipe-In-Pipe Casing Pipe (Flowline and Riser):</u>

Type of CP:	Sacrificial anode
Anode Material:	Aluminum, Zinc & Indium Alloy
Spacing:	316 – 324 feet *
Anode weight:	128 lb. Minimum Alloy Weight

$W_0 := 128 \cdot lb$ _ *Weight of the Anode*

$D := 16 \cdot in$ _ *Pipe Outside Diameter*

$I := 324 \cdot ft$ _ *Separation between Anodes*

$R := 8.4 \cdot \frac{lb}{amp \cdot yr}$ _ *Rate of Consuming, lb/year*

$C := 3.82 \cdot 10^4 \cdot in \cdot \frac{ft}{amp}$

$L_e := \frac{W_0 \cdot C}{D \cdot I \cdot R}$ _ *Anode Life per MMS Letter, Ref. No. MS 5232*

$L_e = 112 yr$

Anode life: 112 years

* <u>Note:</u> 324 feet spacing was used for the calculations to be conservative.

<u>Pipe-In-Pipe Carrier Pipe (Flowline and Riser):</u>
In the as-designed configuration, the exterior of the carrier pipe is part of a dry, sealed annulus with no corrosion potential. Should the outer casing be breached such that water does enter the annulus, corrosion rates within the water-flooded annulus are negligible as oxygen is quickly depleted.

4. *External Protective Coatings*

<u>Pipe-In-Pipe Casing Pipe, Flowline:</u>
External Corrosion Coating: Fusion Bonded Epoxy (FBE), 16 mils minimum and 18 mils nominal

<u>Pipe-in-Pipe Carrier Pipe, Flowline:</u>
External Corrosion Coating: FBE, 8 mils minimum and 10 mils nominal
Insulation Coating: Inner Layer – Polyurethane Foam, 4 lb/ft^3, 1.535" minimum
Outer Layer – Solid Polyethylene Jacket, 0.08" minimum

5. *Internal Coating and Corrosion Control*

The flowline and riser carrier pipe is internally blasted to remove mill scale from the pipe. The flowline and riser carrier pipes are not internally coated.

The flowline and riser casing pipe is internally blasted and coated with 2mils minimum /3mils nominal of COPON EP 2306 WB internal coating. This coating serves three purposes

- reduces mill scale to help offshore welding operations,
- provides scaling surface for water stops,
- and reduces mill scale build up at water stops to provide a better electrical isolation between casing and carrier pipe.

Separate umbilical tubes convey corrosion inhibitor to each subsea tree. At each tree the flowing stream is injected with corrosion inhibitor.

6. *Water Depth and Elevations*

The water depths along the North Oil Loop at critical locations are listed in Table 7 with the pertinent information to this document highlighted. The maximum and minimum water depths are as follows:

Maximum Water Depth:	-6,350 ft MSL near Riser Touchdown in MC-474, NaKika Host.
Minimum Water Depth:	-5,800 ft MSL in MC-383 at Kepler Wells
Maximum Elevation:	+67 ft MSL in MC-474 at the Host termination flange

Table 7. North Oil Loop, Water Depth at Critical Locations

	Location	Water Depth (ft)
Kepler Well K-1 Sled (N2)	MC-383	-5,800
Kepler Well K-2 Sled (N1)	MC-429	-5,800
Ariel Well A-1 Sleds (N8 and N7)	MC-429	-6,250
Ariel Well A-3 Sleds (N6 and N5)	MC-429	-6,150
Ariel Well A-4 Sled (N3, N4)	MC-429	-6,150
Midline Sled (N10)	MC-473	-6,225
Flowline to SCR Transition for K-2 to Host	MC-474	-6,290
SCR Touchdown for K-2 to Host	MC-474	-6,310
Flowline to SCR Transition for A-1 to Host	MC-474	-6,300
SCR Touchdown for A-1 to Host	MC-474	-6,340
Riser Flex-Joint	MC-474	-70
Host SCR Termination	MC-474	+67

7. *Design Capacity of Flowlines*

The North flowline loop is designed for a maximum flow-rate of 50,000 BFPD/100 MMSCFD.

8. *Source Pressures and Temperatures*

The pressure design calculations for the entire North Oil Loop are based on the maximum SITP at Ariel well A-4 and the calculated SITP at 0 feet MSL of the riser top. Local SITP is based on the change in pressure due to the difference in elevation.

Maximum SITP at A-4:	6,500 psig
Maximum SITP at 0 feet MSL of the riser top:	5,600 psig

Flowline operating temperature is 40 °F to 110 °F

The subsea tree is equipped with three pressure barriers in the form of hydraulically actuated fail-close valves. These are the Production Master Valve (PMV), the Production Wing Valve (PWV) and the Production Shut Down Valve (PSDV) as shown in the attached Safety Schematic and Flowline Diagram Drawings 00-012-3002 (Attachment 2). In addition, ROV operable isolation valves are located on the flowline sleds and at each well.

When flowing the wells, pressure is managed using remotely controlled subsea chokes located on the subsea trees. Pressure sensors are positioned on the subsea tree to facilitate control of the subsea production system.

9. *Downstream Facilities and Design Pressure*

Topside sensors monitor flowline arrival pressure. Each flowline is fitted with a remotely actuated fail-close shutdown valve (SDV) as shown on the Safety Schematic and Flowline Diagram (see Attachment 2, drawing 00-012-3002). There are dual, redundant SDV and pressure sensors that control each SDV. In addition, a control valve is used to control flow rate and pressure. Each SDV is a API 6A 10,000 psig working pressure power actuated, fail –close type valve. Each SDV is designed to safely contain the source pressure produced by the wells. The SDVs are controlled from the platform Master Control System (MCS) and remain open only so long as system data indicates safe a operation mode. There are PSL and PSH sensors just upstream of the platform flowline SDV. Under normal operating conditions, the arriving pressure is controlled by the subsea chokes such that it is approximately 200 - 225 psig as the produced fluid flows into the platform inlet separator.

Additional details concerning the downstream facilities design are contained in the Na Kika Host expansion Permit application previously submitted to the MMS.

10. *Pipe Collapse Design*

The casing pipe is subjected to external hydrostatic pressure at depth and has been designed to resist collapse. Flowline jumpers, well jumpers and sled piping as well as sled pipe spools are exposed to sea water and are subjected to external hydrostatic pressure. Theses pipe segments are also checked against collapse

For the pipe segment considered in this document, the most highly loaded point is at Well A-4 sled N3 of –6,340 feet MSL. The calculations are performed for critical location along this pipe segment where either the pipe property changes or the water depth is the maximum. The calculated safety factors against collapse are summarized in Table 8. Detailed calculations are presented in Attachment 3, Calculations 1, 2, and 3. All the calculations are performed by using MathCAD, a commercial math calculation software.

Table 8. Safety Factors Against Pipe Collapse

Calculation	Pipe Description	Water Depth (feet)	Collapse Pressure (psig)	Collapse Safety Factors
1	Sled, 5" Pipe: 5.5625" x0.750", API 5L, X65, Seamless	-5,800	17,419	6.37
2	Sled, 10" Pipe: 10.750"x0.875", API 5L, X70, Seamless	-5,800	10,817	3.96
3	Flowline Casing Pipe: 16.000"x0.750", API 5L, X70, DSAW	-6,150	4,643	1.70

11. *Pipe Internal Design Pressure and MAOP Calculations*

As the planned flowline facility is in deepwater, external pressure is included in the pipe stress calculations for those parts of the system that are exposed to seawater. This is in accordance **ASME B31.8 Gas Transmission and Distribution Piping Systems**, ***A842.221 Hoop Stress.***

For consistency the same calculation format is used for each segment. For pipe-in-pipe carrier pipes and pipes above sea level, the external pressure equals zero. The pipe internal design pressure calculated is identical to pressure calculated using the notation of Paragraph ***250.152 of 30 CFR 250 Subpart J.***

A linear pressure gradient along the loop based on the maximum SITP at the wellhead (Ariel-4) and the 0 feet MSL of the riser top is used to calculate the local SITP. The pressure calculations are performed for the critical points or locations where either the pipe and/or the environmental properties change along the pipeline loop. Calculations are performed for the cases listed in Table 9 with the results summarized in the next section and details in Attachment 3.

Table 9. Calculation Cases for Carrier Pipe Internal Pressure Design

Calculation	Carrier Pipe Segments	Pipe Description	Water Depth (feet)	Exposed to Seawater	Design Factor
4	Sled N2, 5" Sled Pipe	5.5625" x 0.750", API 5L, X65, Seamless	-5,800	Yes	0.72
5	Sled N2, 10" Sled Pipe	10.750" x 0.875", API 5L, X70, Seamless	-5,800	Yes	0.72
6	Flowline at N2	10.750" x 0.812", API 5L, X70, Seamless	-5,800	No	0.72
	Flowline at N3	10.750" x 0.812", API 5L, X70, Seamless	-6,150	No	0.72
7	Sled N3, 5" Sled Pipe	5.5625" x 0.750", API 5L, X65, Seamless	-6,150	Yes	0.72
8	Sled N3, 10" Sled Pipe	10.750" x 0.875", API 5L, X70, Seamless	-6,150	Yes	0.72

Term Definitions in the Calculations

Local SITP

The Local SITP along the flowline system is calculated based on the maximum SITP at wellhead and at the top of riser assuming the well with the maximum SITP is producing by itself. A column of fluid extending from the wellhead to the top of the riser on the Nakika Host Platform results in a linear pressure gradient along the flowline and riser length. This pressure gradient is used to calculate the "local" shut-in pressure at all points along the flowline segment.

Design Pressure

The Design Pressure is calculated based on the "Thin" wall pressure design formula in accordance with ASME B31.8 Gas transmission and Distribution piping Systems, *A842.221 Hoop Stress* and paragraph *250.1002 of 30 CFR 250 Subpart J.* As the planned flowline facility is in deepwater, external pressure is included in the pipe stress calculations for those parts of the system that are exposed to seawater. For consistency the same calculation format is used for each location along the segment.

"Internal" Hydrotest Pressure

The internal hydrotest pressure is calculated based on 1.25 × the Top of Riser Shut-in Pressure as well as the hydrotest fluid gradient. If the hydrotest is performed onshore, there will be no hydrotest fluid gradient. This pressure is the pressure that would be "read" on a gauge placed at that particular location.

"Effective" Hydrotest Pressure

The "effective" hydrotest pressure is the net pressure the pipe experiences, which is calculated by subtracting the external pressure from the internal test pressure at the calculation location. If the hydrotest is performed onshore, there will be no "external" pressure.

Hoop Stress during Hydrotest

The hoop stress due to the net pressure the pipe experiences should not exceed 95% of SMYS of the pipe during hydrotest. For items tested onshore and offshore, there will be two (2) associated calculations.

Required Hydrotest Pressure Check

The "required" hydrotest pressure at any location is required to be 1.25 times the "local" shut-in pressure subtracting the hydrostatic pressure where appropriate at that location. Thus, using the "local" shut-in pressure at each location as a basis, the "effective" hydrotest pressure is confirmed to be larger than the "required" hydrotest pressure.

MAOP Determination

The Maximum Allowable Operating Pressure (MAOP) at a particular location along the flowline segment is determined by the lowest of the following:

- 80% the Hydrotest Pressure
- Pipe Design Pressure
- Design Pressure for Flanges, Valves, Fittings and/or other components which are present at the calculation location

If a particular location in the flowline (i.e. flowline sled) is hydrotested multiple times (i.e. onshore and offshore), the test resulting in the "highest" minimum hydrotest pressure will dictate the MAOP.

Summary of Internal Pressure Design Calculations

The allowable hoop stress is 72% of SMYS for flowline design, 60% of SMYS for riser design and 95% of SMYS during hydrotest. The calculated results are summarized in Table 10 and depicted in Figure 6. Detailed calculations are presented in Attachment 4. In summary the flowline segment from the N2 sled to the N3 sled has a MAOP of 7,614 psig.

Table 10. Summary of Pressure Design Calculation

Item	Description	Location	Water Depth	External Pressure	Design Pressure	"Effective" Hydrotest Pressure(1)	Standard Hydrotest Pressure MAOP(2)	Design Pressure for Fittings at Water Depth(3)	MAOP(4)	"Local" Shut-in Pressure(5)	Hoop Stress during Hydrotest
			fsw	psig	psig	psig	psig	psig	psig	psig	%SMYS
1	5.5625" x 0.750", X65	5" N2 Sled Piping	-5,800	2,578	15,198	7,018	8,192	9,228	8,192	6,449	41.2%
2	10.750"x0.875", X70	10" N2 Sled Pipe Spool	-5,800	2,578	10,782	7,018	8,192	9,228	8,192	6,449	63.3%
3	10.750"x0.812", X70	Flowline at Well K-1 Sled N2	-5,800	0	7,614	9,595	7,676	9,228	7,614	6,449	92.6%
4	10.750"x0.812", X70	Flowline at Well A-4 Sled N3	-6,150	0	7,614	9,751	7,801	9,383	7,614	6,500	94.1%
5	10.750"x0.875", X70	10" N3 Sled Pipe Spool	-6,150	2,733	10,938	7,018	8,347	9,383	8,347	6,500	63.3%
6	5.5625" x 0.750", X65	5" N3 Sled Piping	-6,150	2,733	15,354	7,018	8,347	9,383	8,347	6,500	41.2%
								Minimum	7,614		
								Maximum	8,347		

1) The "Effective" Hydrotest Pressure is the net pressure the pipe experiences during hydrotest, such as:

"Effective" Hydrotest Pressure = (1.25 x SITP @ Top of Riser) + Pfluid (Internal Fluid Presure) - Pstatic (External Pressure of Sea Water, if exposed to seawater)

2) Standard Hydrotest Pressure MAOP (Standard MAOP) is 80% of the "Effective" Hydrotest Pressure + External Pressure of Sea Water.

3) Design pressure for fittings or valves + external pressure at the fittings or valves.

4) MAOP is the least of internal design pressure, standard MAOP and minimum design pressure of fittings, flanges and valves where applicable.

5) Pressure profile is based on the maximum SITP at the wellhead and at 0 feeet MSL of the riser top given in Design Basis Document. A linear pressure gradient is used.

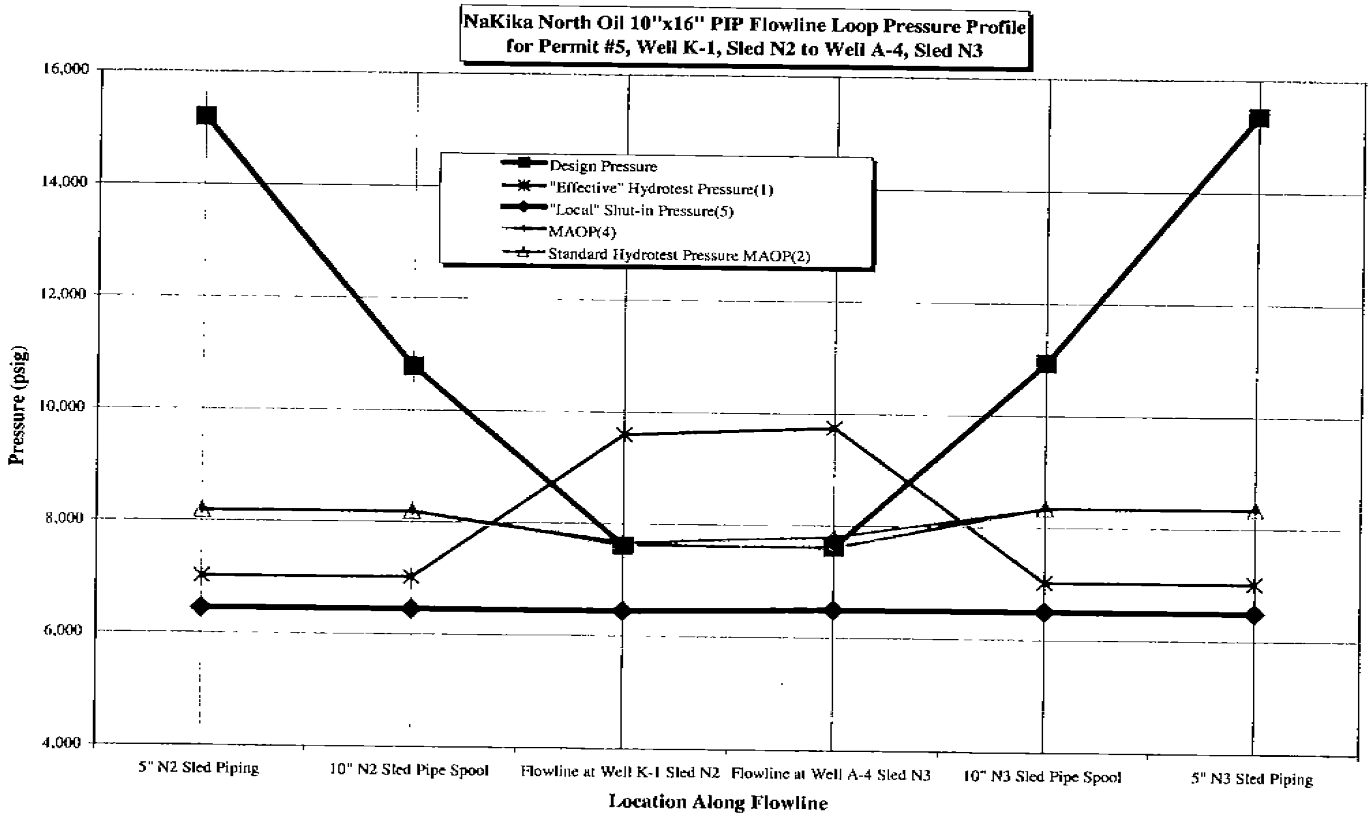

Figure 5. Pressure Design Profile

12. *Pressure of Flanges, Fittings, and Valves*

Flanges:
API 6A 10,000 psig operating pressure.
MAOP = 10,000 psig

5" Manual Gate Valves (on sleds):
API 6A 10,000 psig operating, fabricated from material conforming to temperature classification "P"
MAOP = 10,000 psig

10" Gate Actuated Valves On Initiation Sleds Except Gas Lift Sleds:
API 6A 6,650 psig operating fabricated from material conforming to temperature classification "P"
MAOP = 6,650 psig

Fittings:
Forged Steel Fittings to comply with MSS SP75 "Specification for High test Wrought Butt Weld Fittings", forged material is ASTM A694 F-70. Designed to conform to ASME pressure vessel code, Section VIII, division 1, 2 and 3. Burst Pressure and Design Working Pressure are equal to or greater than the adjoining pipe.

13. *Hydrostatic Test Pressure and Duration*

After installation is completed, the riser, flowline, and startup sled will be tested together from a pig trapper located on the NaKika Host, i.e., the piping between the riser termination flex-joint and pig trappers on the platform will be tested. The flowline and well jumpers are fabricated onshore after pipeline installation in order to get a more precise fit between the respective connecting points on the subsea sleds. As noted previously, these jumpers will be hydrostatically tested onshore after fabrication and just prior to installation. Once all jumpers are installed, a nominal "stand-up" pressure test will be performed in order to test the mechanical connectors' seal and integrity.

Test pressure has been calculated to be no less than 125% of maximum possible pressure at all points in the flowline system. The required Maximum Allowable Operating Pressure (MAOP) at the wellhead of Ariel 4 is 6,500 psig. The required MOP at the TLP (+67 ft MSL) end of the flowline is 5,590 psig. The test pressure and duration can be summarized in the following table.

Table 11. Hydrostatic Test Pressure Summary

Test Medium:	Seawater
Test gauge elevation	+67 ft MSL
Minimum Pressure:	= 6,988 psig (125% of MAOP at top)
Maximum Pressure:	= 7,188 psig (200 psig allowance)
Duration:	8 hours minimum

14. *Electrical Heating*

To enable single flowline flow assurance methods, an electrically heated pipe-in-pipe flowline will be used. A/C power will be applied directly to the ten-inch carrier pipe. This power is applied at the middle of each flowline segment via a mid-line connector. The mid-line connectors are ASTM A-694 steel forgings welded in-line with the flowline pipe. The connectors were analyzed employing ASME Section VII Div. 2 acceptance criteria. The pipe's electrical resistance (more accurately known as the "skin effect") directly heats the inner pipe. The outer pipe remains grounded to subsea sleds on either side of he connector and the seawater. Voltage drops across the inner pipe until it grounds at the subsea sled ends. Non-metallic bulkheads will be used to electrically insulate the inner pipe from the outer pipe and to prevent flooding of the entire annular area in the case of a casing pipe breech.

15. *Volume of Worst Case Hydrocarbon Release*

The maximum potential release of hydrocarbon is estimated in accordance with 30CFR250, Section 254.47. The release estimate is based on the following:

- Complete failure of the flowline at or near the well site and at the base of the riser.
- Initial well expected flowrate.

Release detection time:	300 seconds
Time to close platform-boarding valve:	60 seconds
Time to close well Production Shut-Down Valve:	300 seconds
Total Time:	660 seconds = 0.00764 days

For a line failure at the base of the A-4 sled location, the maximum release is the total response time shown above multiplied by the maximum expected flowrate of 50,000 BOPD. In addition, it is assumed that since the flowline is upward sloping from the failure location that all the line fill volume would not be released since it would be contained by hydrostatic pressure. Therefore, the maximum release is 382 barrels

For a line failure near the K-1 well, the maximum release is the total response time shown above multiplied by the maximum expected flowrate of 50,000 BOPD (382 barrels). Since the flowline is downward sloping from the failure location, it is expected that all the line fill volume of 2,930 bbls (line length of approximately 36,223 feet with a volume of 0.0809 bbl/ft) would be released since it would not be contained by hydrostatic pressure. Therefore, the maximum release is: 3,312 barrels (2930 bbls + 382 bbls).

It should be noted that this is certainly a worst case scenario since it is based on early field life flowrates/pressures will decline over time. In addition, the event of water displacing the entire flowline of product is conservative due to the changes in elevation and hydrostatic head.

16. *Umbilical Design Information*

General Information

In addition to the flowlines, five steel tube umbilicals will service the Nakika North fields. The A1 and A4 dynamic umbilicals will be routed through separate pull tubes (I-tubes) at the Nakika Host platform, which will offer protection from mechanical and environmental forces. A bend stiffener at the base of each I-tube will reduce umbilical movements and limit fatigue. The static A3, K12 and KGL umbilicals shall extend from the A1 and A4 subsea terminations to the A3 cluster, Kepler cluster and Kepler Gas Lift Sled respectively.

The umbilical systems for NaKika North field are listed below. One permit flowline segment may employ several umbilical systems. The umbilical systems pertaining to the Permit #5 pipe segments K-1 sled to A-4 sled are highlighted. Plat maps for the Kepler (K12) umbilical system are included in Attachment 1 of the NaKika North Oil Flowline Permit #1. Plat maps for the rest of the umbilicals are also included in Attachment 1 of the NaKika North Oil Flowline Permit #1.

Ariel 1, Static/Dynamic Umbilical System (A1)

- 5 off 1 1/4" OD SeaCAT tubes, layed-up in a central bundle around a center filler.
- 8 off 5/8" OD 19-D tubes
- 4 off 6mm^2 electrical quad cables
- 7 off filler elements on the outer pass

Ariel 4, Static/Dynamic Umbilical System (A4)

- 6 off 1 1/4" OD SeaCAT tubes, layed-up in a central bundle around a center filler
- 9 off 5/8" OD 19-D tubes
- 3 off 6mm^2 electrical quad cables
- 9 off filler elements on the outer pass

Ariel 3, Static Umbilical System (A3)

- 4 off 1 1/4" OD SeaCat tubes, layed-up with 4 fillers in a central bundle around a center filler
- 7 off 5/8" OD 19-D tubes
- 2 off $6mm^2$ electrical quad cables
- 8 off filler elements on the outer pass

Kepler, Static Umbilical System (K12)

- 5 off 1 1/4" OD SeaCAT tubes layed-up in a central bundle around a center filler
- 8 off 5/8" OD 19-D tubes
- 3 off $6mm^2$ electrical quad cables
- 8 off filler elements on the outer pass

Kepler Gas Lift, Static Umbilical System (KGL)

- 2 off 1 1/4" OD SeaCAT tubes
- 2 off 5/8" OD 19-D tubes
- 2 off $6mm^2$ electrical quad cables

The umbilical system tubes, fittings, and connectors will be designed for a maximum operating pressure of 10,000 psi.

Table 12. Summary Umbilical Information:

Cross Section Design Description	Static Section	Dynamic Section
A1 Outside Diameter	5.3 in.	5.5 in.
A1 Weight in air (full)	20.18 lb/ft	21.29 lb/ft
A1 Submerged Weight (full)	13.34 lb/ft	13.02 lb/ft
A4 Outside Diameter	5.7 in.	5.9 in.
A4 Weight in air (full)	23.40 lb/ft	24.63 lb/ft
A4 Submerged Weight (full)	15.33 lb/ft	14.86 lb/ft
A3 Outside Diameter	5.0 in.	NA
A3 Weight in air (full)	16.78 lb/ft	NA
A3 Submerged Weight (full)	10.72 lb/ft	NA
K12 Outside Diameter	5.3 in.	NA
K12 Weight in air (full)	19.95 lb/ft	NA
K12 Submerged Weight (full)	13.14 lb/ft	NA
KGL Outside Diameter	4.3 in.	NA
KGL Weight in air (full)	9.84 lb/ft	NA
KGL Submerged Weight (full)	4.71 lb/ft	NA

III. INSTALLATION REQUIREMENTS

No trenching is required, as the water depths along the flowline and umbilical routes are greater than 200 ft.

IV. PIPELINE CROSSINGS

There are no pipeline crossings along the route.

V. CONSTRUCTION INFORMATION

- Installation Plans and Construction Method
  Refer to Table 1.

- Project Engineer
  Flowline: Tom Preli (281) 544 4097
  Umbilicals: Katrina Paton (281) 544 2837

VI. ATTACHMENTS

ATTACHMENT 1
Flowline Plat Maps for NaKika North Flowline Permit #5

ATTACHMENT 2
Safety Schematic and Flowline Diagram for NaKika North Flowline Loop

ATTACHMENT 3
Detailed Calculations for Pipe Collapse Design

ATTACHMENT 4
Detailed Calculations for Pipe Internal Pressure Design

ATTACHMENT 1

Flowline Plat Maps for NaKika North Flowline Permit #5

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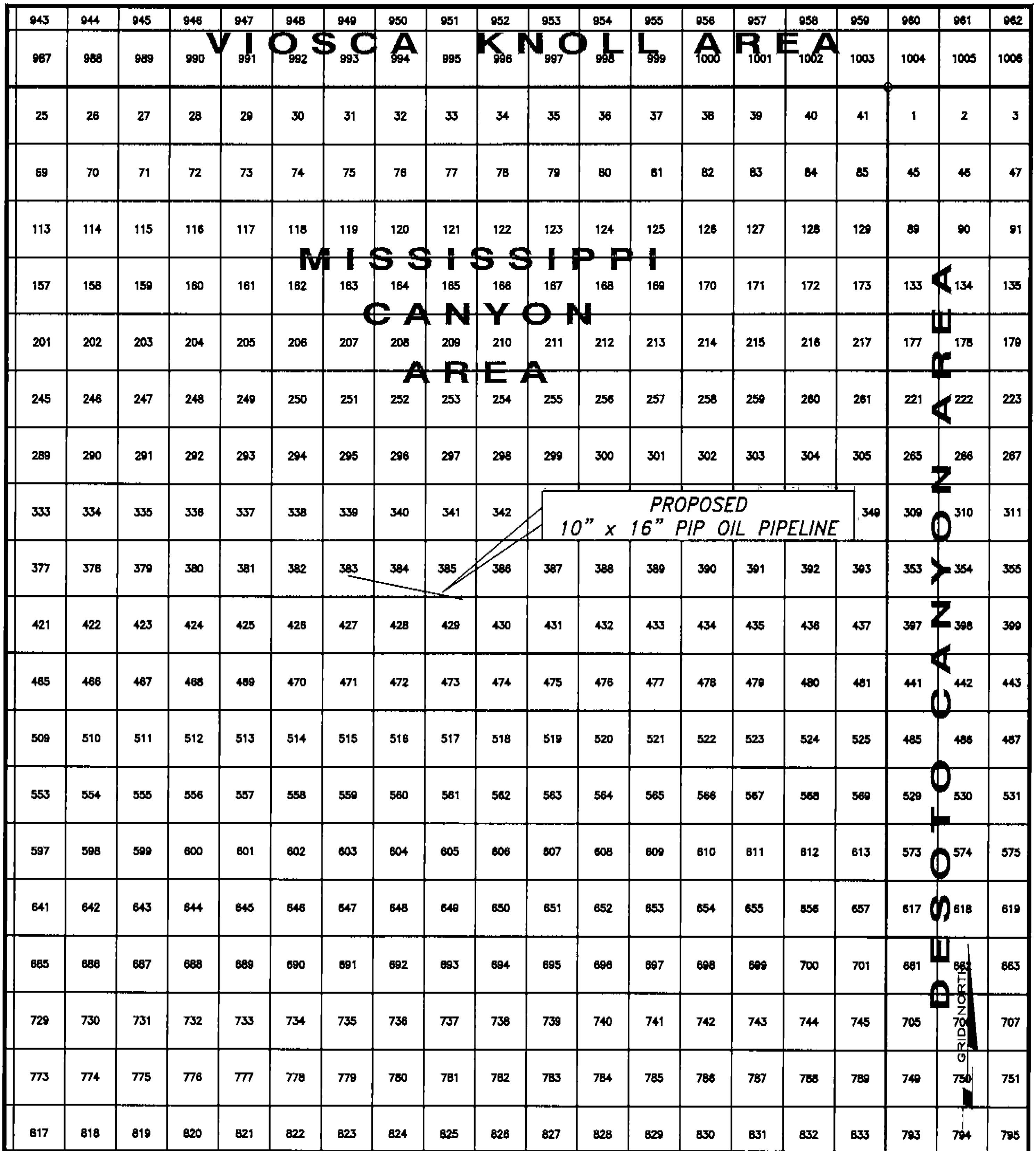

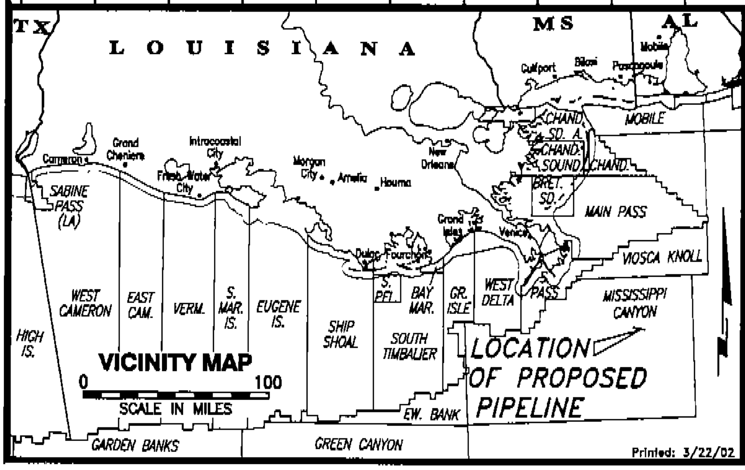

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SHELL OFFSHORE INC.

PROPOSED
10" x 16" PIP OIL PIPELINE
KEPLER WELL #1 TO ARIEL WELL #4
MISSISSIPPI CANYON AREA BLOCKS 383 TO 429
GULF OF MEXICO

JOHN E. CHANCE & ASSOCIATES, INC.

GEODETIC DATUM: NAD 1927
PROJECTION: U.T.M. 16
GRID UNITS: US SURVEY FEET

SCALE IN FEET 0 40,000'

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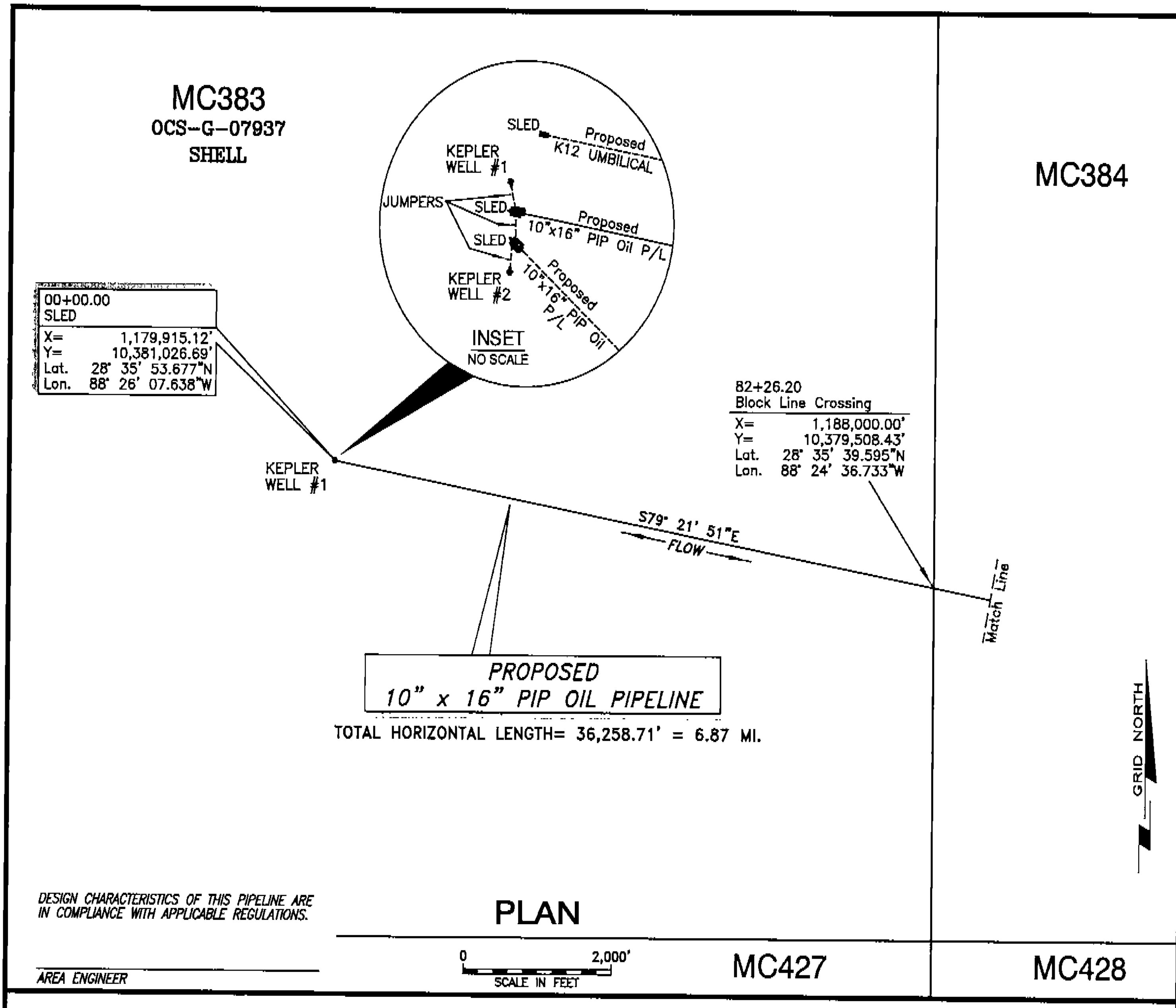
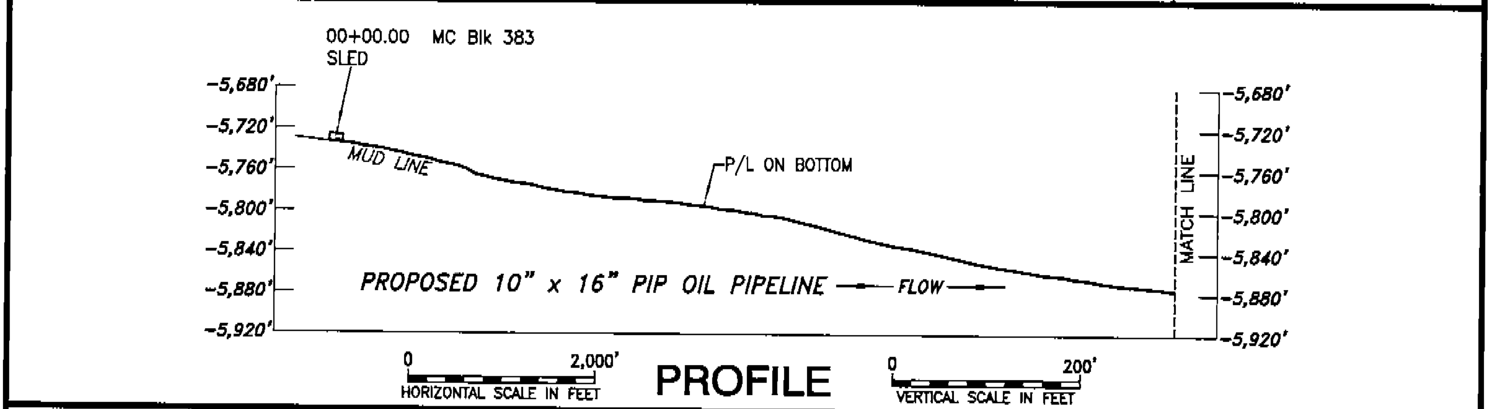


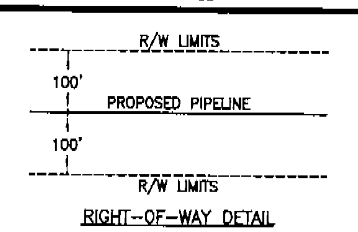


THE RIGHT OF WAY OF THE PROPOSED PIPELINE IS ACCURATELY REPRESENTED.

STATE OF LOUISIANA
LIONEL J. CORMIER
REG. No. 4401
REGISTERED PROFESSIONAL LAND SURVEYOR

Lionel J. Cormier

REG. PROFESSIONAL LAND SURVEYOR NO. 4401
STATE OF LOUISIANA



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KEPLER WELL #1 TO ARIEL WELL #4
MISSISSIPPI CANYON AREA BLOCKS 383 TO 429
GULF OF MEXICO

JOHN E. CHANCE & ASSOCIATES, INC. FUGRO

GEODETIC DATUM: NAD 1927 PROJECTION: U.T.M. 16 GRID UNITS: US SURVEY FEET	SCALE AS SHOWN

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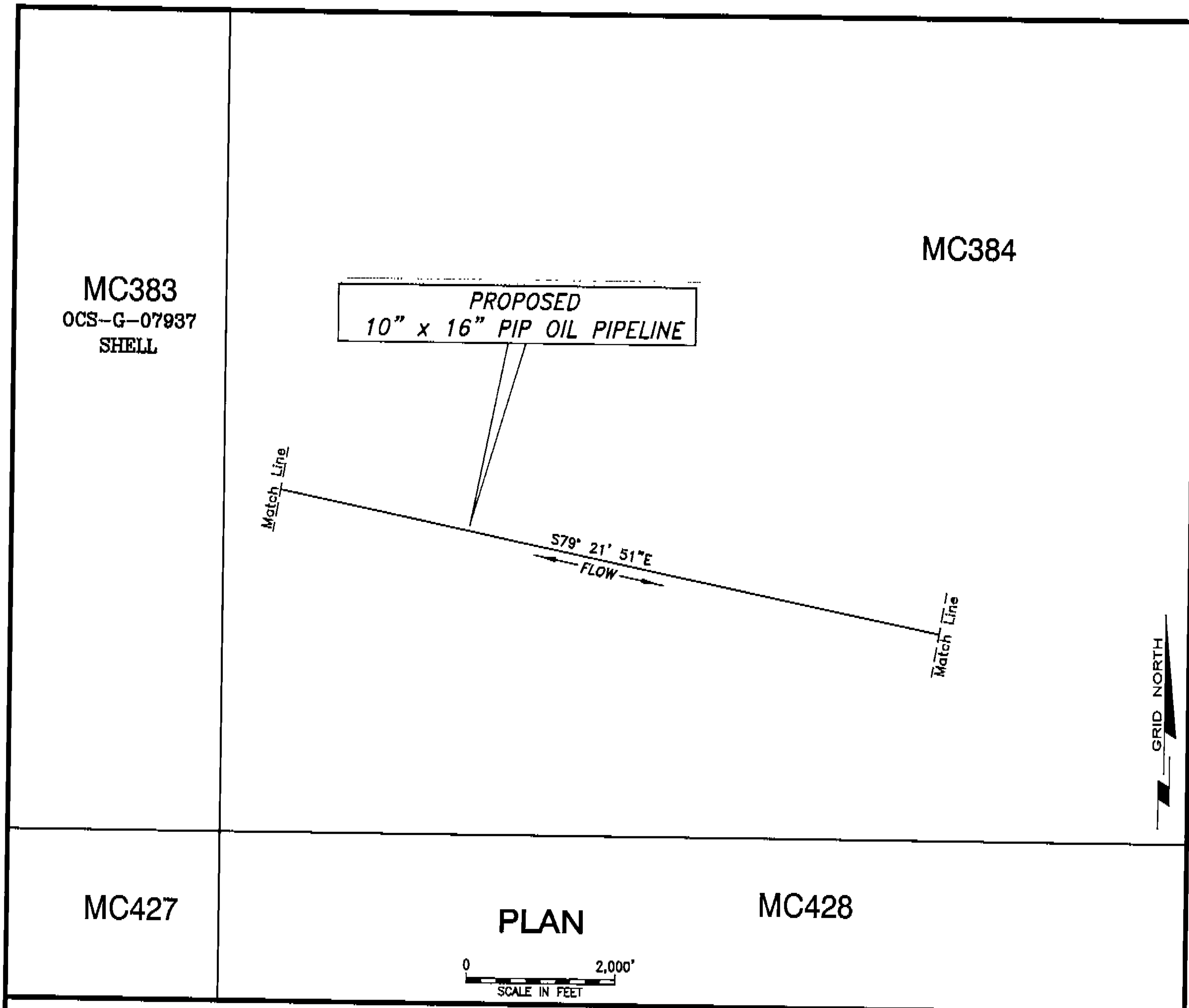

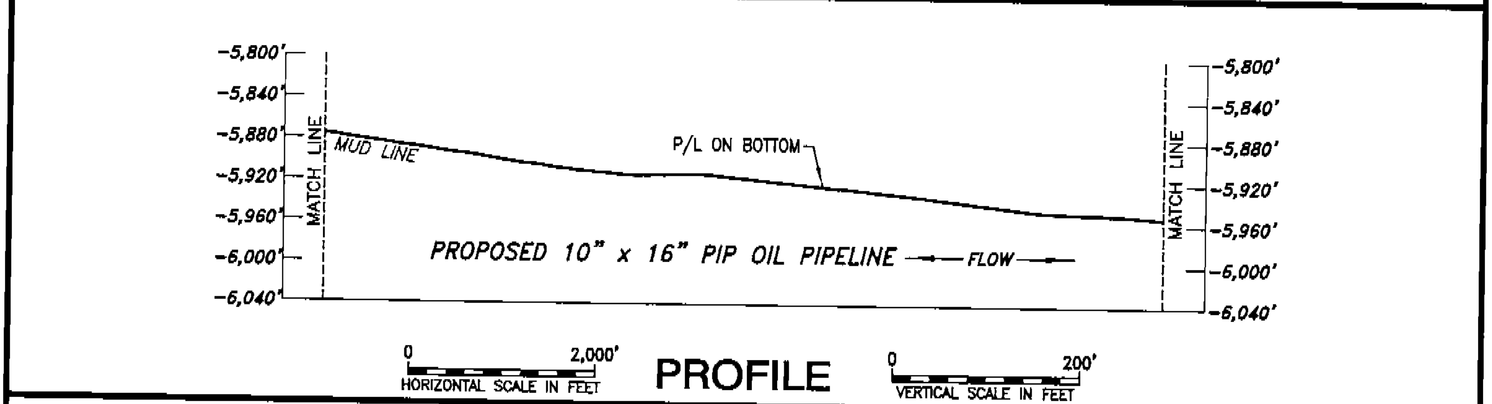

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GEODETIC DATUM: NAD 1927
PROJECTION: U.T.M. 16
GRID UNITS: US SURVEY FEET

SCALE AS SHOWN

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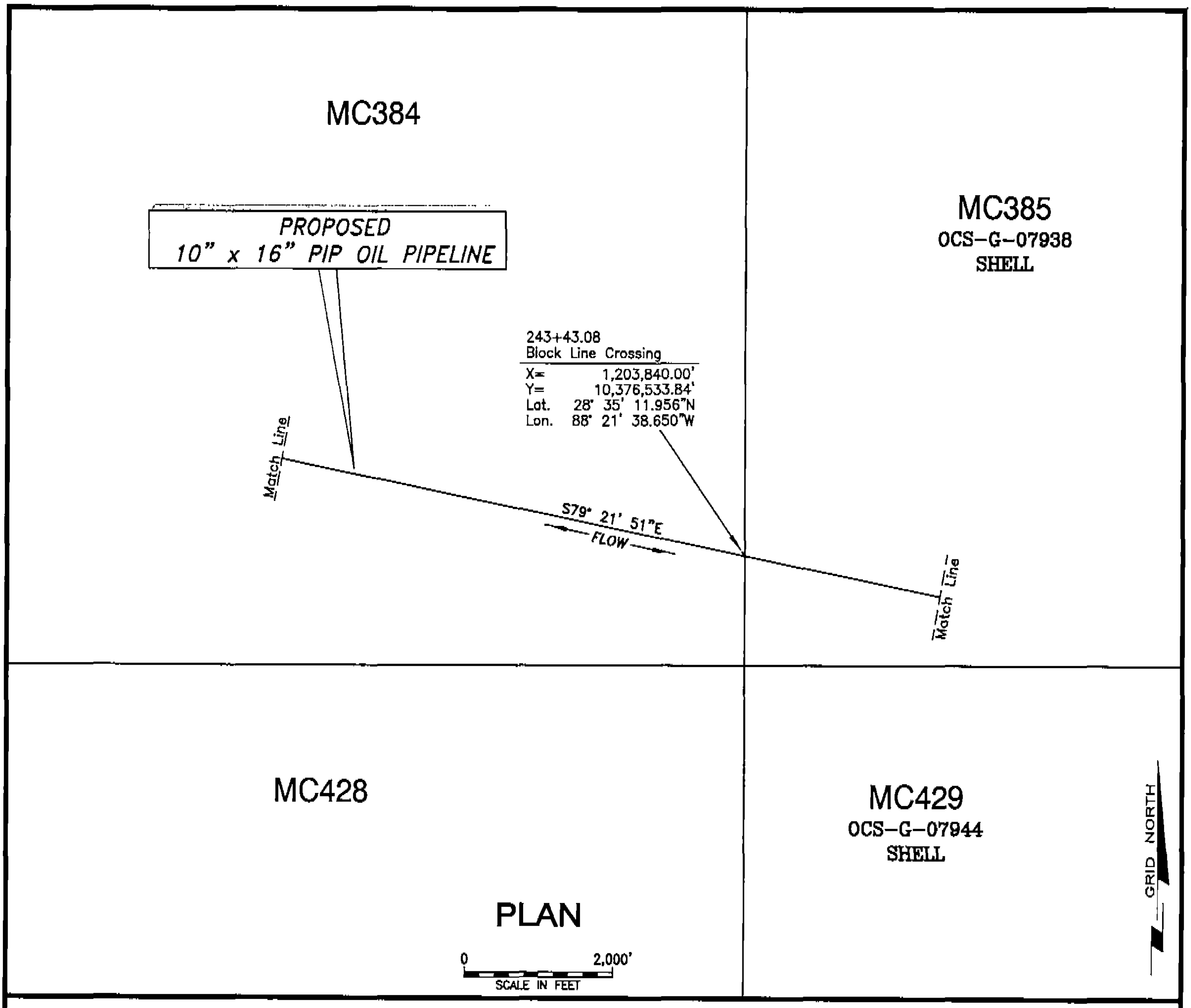

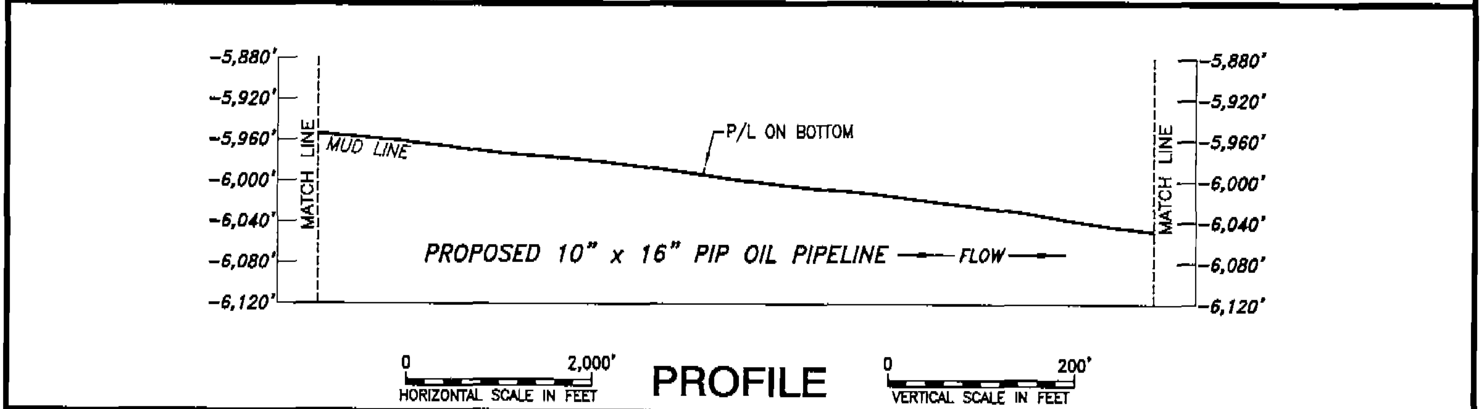

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GEODETIC DATUM: NAD 1927 PROJECTION: U.T.M. 16 GRID UNITS: US SURVEY FEET	SCALE AS SHOWN

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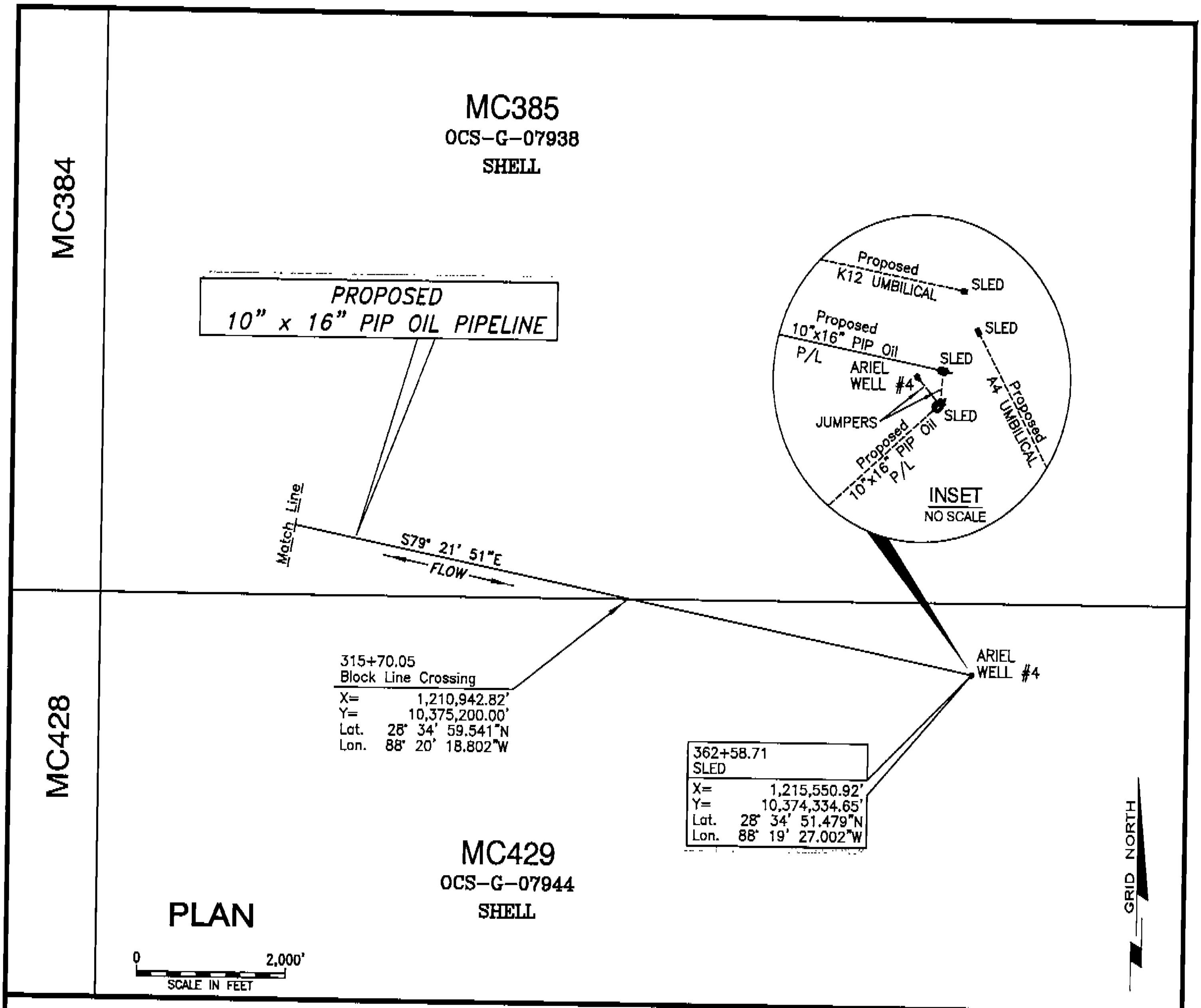

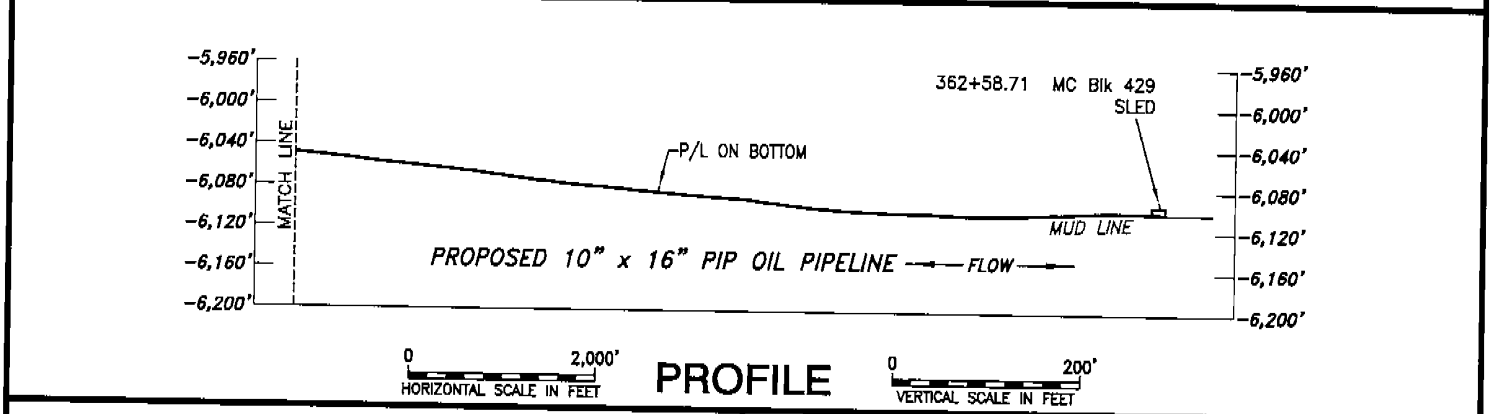

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PROJECTION: U.T.M. 16
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SCALE AS SHOWN

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ATTACHMENT 2

Safety Schematic and Flowline Diagram for NaKika North Flowline Loop (Drawing 00-012-3002)

ATTACHMENT 3

Detailed Calculations for Pipe Collapse Design

Calculation 1. Sled 5" Piping Collapse Design

Constants

Sea Water Specific Weight $\gamma \equiv 64 \cdot lbf \cdot ft^{-3}$

Modulus of Elasticity of Steel $E \equiv 29000 ksi$

Design Data

Outside Diameter for Pipe $D = 5.563in$

Pipeline Wall Thickness $t = 0.75in$

SMYS of Pipe $Y = 65ksi$

Maximum Water Depth at Calculation $H_{max} = -6150ft$

Pipe Collapse Design

The following is based on API RP 1111 (Limit State Design), 3rd edition, July, 1999It is also known as the Shell Formula. The most critical point along the entire pipeline route is the pipe at the maximum water depth.

$H_{max} = -6150ft$

$P_{ex\_max} := \gamma \cdot |H_{max}|$ $P_{ex\_max} = 2733psig$ *_maximum external pressure at calculation*

Pipeline Collapse Pressure

$P_y := 2 \cdot Y \cdot \frac{t}{D}$ $P_y = 17528psi$ *_yield pressure at collapse*

$P_e := 2.2 \cdot \left(\frac{t}{D}\right)^3 \cdot E$ $P_c = 156385psi$ *_elastic collapse pressure*

$P_c := \frac{P_y \cdot P_c}{\sqrt{P_y^{\ 2} + P_e^{\ 2}}}$ $P_c = 17419psi$ *_collapse pressure of the pipeline*

Check Against Pipeline Collapse

$CollapseF := \frac{P_c}{P_{ex\_max}}$ $CollapseF = 6.37$

$CheckP_c :=$ if(CollapseF > 1.5, "OK" , "Not OK")

$CheckP_c =$ "OK"

Calculation 2. Sled Pipe Spool Collapse Design

Constants

Sea Water Specific Weight $\gamma \equiv 64 \cdot \text{lbf} \cdot \text{ft}^{-3}$

Modulus of Elasticity of Steel $E \equiv 29000\text{ksi}$

Design Data

Outside Diameter for Pipe	$D = 10.75\text{in}$
Pipeline Wall Thickness	$t = 0.875\text{in}$
SMYS of Pipe	$Y = 70\text{ksi}$
Maximum Water Depth at Calculation	$H_{max} = -6150\text{ft}$

Pipe Collapse Design

The following is based on API RP 1111 (Limit State Design), 3rd edition, July, 1999It is also known as the Shell Formula. The most critical point along the entire pipeline route is the pipe at the maximum water depth.

$H_{max} = -6150\text{ft}$

$P_{ex\_max} := \gamma \cdot |H_{max}|$ $\quad P_{ex\_max} = 2733\text{psig}$ *_maximum external pressure at calculation*

Pipeline Collapse Pressure

$P_y := 2 \cdot Y \cdot \frac{t}{D}$ $\quad P_y = 11395\text{psi}$ *_yield pressure at collapse*

$P_e := 2.2 \cdot \left(\frac{t}{D}\right)^3 \cdot E$ $\quad P_e = 34405\text{psi}$ *_elastic collapse pressure*

$P_c := \frac{P_y \cdot P_e}{\sqrt{P_y^2 + P_e^2}}$ $\quad P_c = 10817\text{psi}$ *_collapse pressure of the pipeline*

Check Against Pipeline Collapse

$\text{CollapseF} := \frac{P_c}{P_{ex\_max}}$ $\quad \text{CollapseF} = 3.96$

$\text{CheckP}_c := \text{if}(\text{CollapseF} > 1.5, \text{"OK"}, \text{"Not OK"})$

$\text{CheckP}_c = \text{"OK"}$

Calculation 3. Flowline Casing Collapse Design

Constants

Sea Water Specific Weight $\gamma \equiv 64 \cdot \text{lbf} \cdot \text{ft}^{-3}$

Modulus of Elasticity of Steel $E \equiv 29000\text{ksi}$

Design Data

Outside Diameter for Pipe	$D = 16\text{in}$
Pipeline Wall Thickness	$t = 0.75\text{in}$
SMYS of Pipe	$Y = 70\text{ksi}$
Maximum Water Depth at Calculation	$H_{max} = -6150\text{ft}$

Pipe Collapse Design

The following is based on API RP 1111 (Limit State Design), 3rd edition, July, 1999It is also known as the Shell Formula. The most critical point along the entire pipeline route is the pipe at the maximum water depth.

$H_{max} = -6150\text{ft}$

$P_{ex\_max} := \gamma \cdot |H_{max}|$ $\quad P_{ex\_max} = 2733\text{psig}$ $\quad$ *_maximum external pressure at calculation*

Pipeline Collapse Pressure

$P_y := 2 \cdot Y \cdot \frac{t}{D}$ $\quad P_y = 6563\text{psi}$ $\quad$ *_yield pressure at collapse*

$P_e := 2.2 \cdot \left(\frac{t}{D}\right)^3 \cdot E$ $\quad P_e = 6571\text{psi}$ $\quad$ *_elastic collapse pressure*

$P_c := \frac{P_y \cdot P_e}{\sqrt{P_y^2 + P_e^2}}$ $\quad P_c = 4643\text{psi}$ $\quad$ *_collapse pressure of the pipeline*

Check Against Pipeline Collapse

$\text{CollapseF} := \frac{P_c}{P_{ex\_max}}$ $\quad \text{CollapseF} = 1.7$

$\text{CheckP}_c := \text{if}(\text{CollapseF} > 1.5, \text{"OK"}, \text{"Not OK"})$

$\text{CheckP}_c = \text{"OK"}$

ATTACHMENT 4

Detailed Calculations for Pipe Internal Pressure Design

Calculation 4. N2 Sled 5" Piping Pressure Design (1/3)

(All Pressures are gauge Pressures)

Constants

Sea Water Specific Weight $\gamma \equiv 64 \cdot \text{lbf} \cdot \text{ft}^{-3}$

Modulus of Elasticity of Steel $E \equiv 29000\,\text{ksi}$

Design Data

Outside Diameter for Pipe	$D = 5.563\text{in}$
Pipe Wall Thickness	$t = 0.75\text{in}$
SMYS of Pipe	$Y = 65\,\text{ksi}$
Water Depth at Well with the Maximum SITP	$H_{A4} = -6150\text{ft}$
Mean Sea Level Elevation (MSL)	$H_{msl} = 0\,\text{ft}$
Elevation at the Riser Top	$H_{top} = 67\,\text{ft}$
Water Depth at Calculation Location	$H_{local} = -5800\text{ft}$
Maximum SITP of the Flowline Loop, at Well A-4	$P_{sitp} = 6500\text{psig}$
Maxiumu SITP at Mean Sea Level Elevation	$P_{msl} = 5600\text{psig}$
Minimum Design Pressure of Sled Components	$P_{fitting} = 6650\text{psig}$
Construction Design Factor (B31.8) (Line Pipe)	$F = 0.72$
Longitudinal Joint Factor (DSAW or Seamless Pipe)	$f_e = 1$
Temperature Derating Factor (B31.8, Temp. <=250 F)	$f_t = 1$

Calculation 4. N2 Sled 5" Piping Pressure Design (2/3)

1. Internal Pressure Design

Local SITP Calculation

$P_{gradient} := \dfrac{P_{sitp} - P_{msl}}{H_{A4} - H_{msl}}$ $\quad P_{gradient} = -0.146 ft^{-1} psig$ $\quad$ *_pressure gradient assumption*

$P_{sitp1} := P_{sitp} - P_{gradient}(H_{A4} - H_{local})$ $\quad P_{sitp1} = 6449 psig$ $\quad$ *_SITP at calculation location*

$P_{top} := P_{sitp} - P_{gradient}(H_{A4} - H_{top})$ $\quad P_{top} = 5590 psig$ $\quad$ *_SITP at riser top of +67 ft elevation*

Internal Design Pressure (B31.8)

The sled piping is exposed to external pressure.

$P_{ex} := \gamma \cdot |H_{local}|$ $\quad P_{ex} = 2578 psig$ $\quad$ *_external pressure*

$P_i := P_{ex} + \dfrac{(2 \cdot Y \cdot t \cdot f_e \cdot F \cdot f_t)}{D}$ $\quad P_i = 15198 psig$ $\quad$ *_internal design pressure B31.8*

$CheckP_{i1} := if(P_i > P_{sitp1}, "OK", "Not OK")$ $\quad CheckP_{i1} = "OK"$

Hoop Stress during Hydrotest

The onshore hydrotest pressure for all the NaKika North Sleds is 8,300 to 8,350 psig based on approximately 1.25 times the minimum design pressure of the sled components. The required offshore hydrotest pressure is 1.25 times the SITP at riser top (+67ft). The Hoop Stress during hydrotest due to maximuminternal net pressure should not exceed 95% of SMYS.

A. Onshore Test

$P_{Hydro} := 8350 psig$ $\quad$ *_maximum allowable hydrotest pressure on Sled*

$P_{tnet} := P_{Hydro}$ $\quad P_{tnet} = 8350 psig$ $\quad$ *_internal net pressure*

$SH := \dfrac{P_{tnet} \cdot D}{2 \cdot t}$ $\quad SH = 31 ksi$ $\quad$ *_hoop stress, based on thin wall OD*

$\%SMYS := \dfrac{SH}{Y}$ $\quad \%SMYS = 48\%$

$CheckSH := if(\%SMYS < 95\%, "OK", "Not OK")$ $\quad CheckSH = "OK"$

Calculation 4. N2 Sled 5" Piping Pressure Design (3/3)

B. Offshore Test

$P_{ex} = 2578psig$		*_external pressure*
$P_{fluid} := (H_{top} - H_{local})\cdot\gamma$	$P_{fluid} = 2608psig$	*_testing water head pressure*
$P_{Hydro} := 1.25 \cdot P_{top} + P_{fluid}$	$P_{Hydro} = 9595psig$	*_local minimum hydrotest pressure*
$P_{Hydro\_max} := P_{Hydro} + 200 \cdot psig$	$P_{Hydro\_max} = 9795psig$	*_maximum hydrotest pressure*
$P_{tnet\_max} := P_{Hydro\_max} - P_{ex}$	$P_{tnet\_max} = 7218psig$	*_maximum internal net test pressure*
$SH := \dfrac{P_{tnet\_max} \cdot D}{2 \cdot t}$	$SH = 27ksi$	*_hoop stress, based on thin wall OD*
$\%SMYS := \dfrac{SH}{Y}$	$\%SMYS = 41\%$	
CheckSH := if(%SMYS < 95%, "OK" , "Not OK")		CheckSH = "OK"

2. Offshore Hydrostatic Test Pressure and MAOP

The required hydrostatic test (hydrotest) pressure is 1.25 of the top SITP. The local test pressure should not be less than 1.25 of the local SITP. The effective hydrotest pressure is the net pressure the pipe experiences. For internal carrier pipe not subjected to hydrostatic pressure, the effective test pressure is the same as the hydrotest internal pressure. The Maximum Allowable Operating Pressure (MAOP) is the lowest of: a) Pipe Design pressure; b) 80% of Minimum Hydrotest Pressure and c) Minimum Design Pressure for Valves, Flanges, Fittings or other Components where applicable.

Effective Hydrotest Net Pressure

$P_{tnet} := P_{Hydro} - P_{ex}$	$P_{tnet} = 7018psig$	*_minimum hydrotest net pressure*
$P_{eff} := P_{tnet}$	$P_{eff} = 7018psig$	*_effective test pressure*
$P_{req} := 1.25 \cdot P_{sitp1} - P_{ex}$	$P_{req} = 5483psig$	*_required local net test pressure*
$CheckP_{eff} := if(P_{eff} \ge P_{req}, \text{"OK"}, \text{"Not OK"})$		$CheckP_{eff} = \text{"OK"}$

MAOP

$MAOP_{hydro} := 0.80 \cdot P_{eff} + P_{ex}$		*_MAOP based on hydrotest pressure*
$MAOP_{hydro} = 8192psig$		
$P_{fittingH} := P_{fitting} + \gamma \cdot \lvert H_{local} \rvert$	$P_{fittingH} = 9228psig$	*_minimum design pressure for the components on sled at sled water depth*
$MAOP := min(MAOP_{hydro}, P_i, P_{fittingH})$		*_MAOP at the calculation location*
$MAOP = 8192psig$		
$CheckMAOP := if(MAOP \ge P_{sitp1}, \text{"OK"}, \text{"Not OK"})$		CheckMAOP = "OK"

Calculation 5. N2 Sled 10" Pipe Spool Pressure Design (1/3)

(All Pressures are gauge Pressures)

Constants

Sea Water Specific Weight	$\gamma \equiv 64 \cdot \mathrm{lbf} \cdot \mathrm{ft}^{-3}$
Modulus of Elasticity of Steel	$E \equiv 29000\,\mathrm{ksi}$

Design Data

Outside Diameter for Pipe	$D = 10.75\mathrm{in}$
Pipe Wall Thickness	$t = 0.875\mathrm{in}$
SMYS of Pipe	$Y = 70\mathrm{ksi}$
Water Depth at Well with the Maximum SITP	$H_{A4} = -6150\mathrm{ft}$
Mean Sea Level Elevation (MSL)	$H_{msl} = 0\,\mathrm{ft}$
Elevation at the Riser Top	$H_{top} = 67\,\mathrm{ft}$
Water Depth at Calculation Location	$H_{local} = -5800\mathrm{ft}$
Maximum SITP of the Flowline Loop, at Well A-4	$P_{sitp} = 6500\mathrm{psig}$
Maxiumu SITP at Mean Sea Level Elevation	$P_{msl} = 5600\mathrm{psig}$
Minimum Design Pressure of Sled Components	$P_{fitting} = 6650\mathrm{psig}$
Construction Design Factor (B31.8) (Line Pipe)	$F = 0.72$
Longitudinal Joint Factor (DSAW or Seamless Pipe)	$f_e = 1$
Temperature Derating Factor (B31.8, Temp. <=250 F)	$f_t = 1$

Calculation 5. N2 Sled 10" Pipe Spool Pressure Design (2/3)

1. Internal Pressure Design

Local SITP Calculation

$P_{gradient} := \dfrac{P_{sitp} - P_{msl}}{H_{A4} - H_{msl}}$ $\quad P_{gradient} = -0.146\text{ft}^{-1}\,\text{psig}$ $\quad$ *_pressure gradient assumption*

$P_{sitp1} := P_{sitp} - P_{gradient}\left(H_{A4} - H_{local}\right)$ $\quad P_{sitp1} = 6449\text{psig}$ $\quad$ *_SITP at calculation location*

$P_{top} := P_{sitp} - P_{gradient}\left(H_{A4} - H_{top}\right)$ $\quad P_{top} = 5590\text{psig}$ $\quad$ *_SITP at riser top of +67 ft elevation*

Internal Design Pressure (B31.8)

The sled piping is exposed to external pressure.

$P_{ex} := \gamma \cdot \left|H_{local}\right|$ $\quad P_{ex} = 2578\text{psig}$ $\quad$ *_external pressure*

$P_i := P_{ex} + \dfrac{\left(2 \cdot Y \cdot t \cdot f_e \cdot F \cdot f_t\right)}{D}$ $\quad P_i = 10782\text{psig}$ $\quad$ *_internal design pressure B31.8*

$CheckP_{i1} := \text{if}\left(P_i > P_{sitp1}, \text{"OK"}, \text{"Not OK"}\right)$ $\quad CheckP_{i1} = \text{"OK"}$

Hoop Stress during Hydrotest

The onshore hydrotest pressure for all the NaKika North Sleds is 8,300 to 8,350 psig based on approximately 1.25 times the minimum design pressure of the sled components. The required offshore hydrotest pressure is 1.25 times the SITP at riser top (+67ft). The Hoop Stress during hydrotest due to maximuminternal net pressure should not exceed 95% of SMYS.

A. Onshore Test

$P_{Hydro} := 8350\,\text{psig}$ $\quad$ *_maximum allowable hydrotest pressure on Sled*

$P_{tnet} := P_{Hydro}$ $\quad P_{tnet} = 8350\text{psig}$ $\quad$ *_internal net pressure*

$SH := \dfrac{P_{tnet} \cdot D}{2 \cdot t}$ $\quad SH = 51\,\text{ksi}$ $\quad$ *_hoop stress, based on thin wall OD*

$\%SMYS := \dfrac{SH}{Y}$ $\quad \%SMYS = 73\%$

$CheckSH := \text{if}(\%SMYS < 95\%, \text{"OK"}, \text{"Not OK"})$ $\quad CheckSH = \text{"OK"}$

Calculation 5. N2 Sled 10" Pipe Spool Pressure Design (3/3)

B. Offshore Test

$P_{ex} = 2578\text{psig}$		*_external pressure*
$P_{fluid} := (H_{top} - H_{local})\cdot\gamma$	$P_{fluid} = 2608\text{psig}$	*_testing water head pressure*
$P_{Hydro} := 1.25 \cdot P_{top} + P_{fluid}$	$P_{Hydro} = 9595\text{psig}$	*_local minimum hydrotest pressure*
$P_{Hydro\_max} := P_{Hydro} + 200\cdot\text{psig}$	$P_{Hydro\_max} = 9795\text{psig}$	*_maximum hydrotest pressure*
$P_{tnet\_max} := P_{Hydro\_max} - P_{ex}$	$P_{tnet\_max} = 7218\text{psig}$	*_maximum internal net test pressure*
$SH := \dfrac{P_{tnet\_max}\cdot D}{2\cdot t}$	$SH = 44\text{ksi}$	*_hoop stress, based on thin wall OD*
$\%SMYS := \dfrac{SH}{Y}$	$\%SMYS = 63\%$	
CheckSH := if(%SMYS < 95%, "OK", "Not OK")		CheckSH = "OK"

2. Offshore Hydrostatic Test Pressure and MAOP

The required hydrostatic test (hydrotest) pressure is 1.25 of the top SITP. The local test pressure should not be less than 1.25 of the local SITP. The effective hydrotest pressure is the net pressure the pipe experiences. For internal carrier pipe not subjected to hydrostatic pressure, the effective test pressure is the same as the hydrotest internal pressure. The Maximum Allowable Operating Pressure (MAOP) is the lowest of: a) Pipe Design pressure; b) 80% of Minimum Hydrotest Pressure and c) Minimum Design Pressure for Valves, Flanges, Fittings or other Components where applicable.

Effective Hydrotest Net Pressure

$P_{tnet} := P_{Hydro} - P_{ex}$	$P_{tnet} = 7018\text{psig}$	*_minimum hydrotest net pressure*
$P_{eff} := P_{tnet}$	$P_{eff} = 7018\text{psig}$	*_effective test pressure*
$P_{req} := 1.25 \cdot P_{sitp1} - P_{ex}$	$P_{req} = 5483\text{psig}$	*_required local net test pressure*
$CheckP_{eff} := \text{if}(P_{eff} \geq P_{req}, \text{"OK"}, \text{"Not OK"})$		$CheckP_{eff} = \text{"OK"}$

MAOP

$MAOP_{hydro} := 0.80 \cdot P_{eff} + P_{ex}$		*_MAOP based on hydrotest pressure*
$MAOP_{hydro} = 8192\text{psig}$		
$P_{fittingH} := P_{fitting} + \gamma \cdot \lvert H_{local} \rvert$	$P_{fittingH} = 9228\text{psig}$	*_minimum design pressure for the components on sled at sled water depth*
$MAOP := \min(MAOP_{hydro}, P_i, P_{fittingH})$		*_MAOP at the calculation location*
$MAOP = 8192\text{psig}$		
$CheckMAOP := \text{if}(MAOP \geq P_{sitp1}, \text{"OK"}, \text{"Not OK"})$		CheckMAOP = "OK"

Calculation 6. Flowline Carrier Pipe Pressure Design (1/3)

(All Pressures are gauge Pressures)

Calculation Locations

Calculation Location 1: Flowline Carrier Pipe at K-1 Start-Up Sled (N2)

Calculation Location 2: Flowline Carrier Pipe at A-4 Sled (N3)

Constants

Sea Water Specific Weight	$\gamma \equiv 64 \cdot \mathrm{lbf} \cdot \mathrm{ft}^{-3}$
Modulus of Elasticity of Steel	$E \equiv 29000\,\mathrm{ksi}$

Design Data

Outside Diameter for Pipe	$D = 10.75\mathrm{in}$
Pipe Wall Thickness	$t = 0.812\mathrm{in}$
SMYS of Pipe	$Y = 70\mathrm{ksi}$
Water Depth at the Well with the Max. Shut-In-Tube-Pressure (SITP)	$H_{A4} = -6150\mathrm{ft}$
Mean Sea Level Elevation (MSL)	$H_{msl} = 0\,\mathrm{ft}$
Elevation at the Riser Top	$H_{top} = 67\,\mathrm{ft}$
Water Depth at Calculation Location 1	$H_{local1} = -5800\mathrm{ft}$
Water Depth at Calculation Location 2	$H_{local2} = -6150\mathrm{ft}$
Maximum SITP of the Flowline Loop, at Well A-4	$P_{sitp} = 6500\mathrm{psig}$
Maximum SITP at Mean Sea Level Elevation	$P_{msl} = 5600\mathrm{psig}$
Minimum Design Pressure of Sled Components	$P_{fitting} = 6650\mathrm{psig}$
Construction Design Factor (B31.8) (Line Pipe)	$F = 0.72$
Longitudinal Joint Factor (DSAW or Seamless Pipe)	$f_e = 1$
Temperature Derating Factor (B31.8, Temp. <=250 F)	$f_t = 1$

Calculation 6. Flowline Carrier Pipe Pressure Design (2/3)

Location 1, Flowline at K-1 Sled

1. Internal Pressure Design

Local SITP Calculation

$P_{gradient} := \dfrac{P_{sitp} - P_{msl}}{H_{A4} - H_{msl}}$ $\quad P_{gradient} = -0.146ft^{-1}\,psig$ _pressure gradient assumption

$P_{sitp1} := P_{sitp} - P_{gradient} \cdot (H_{A4} - H_{local1})$ $\quad P_{sitp1} = 6449psig$ _SITP at calculation location

$P_{top} := P_{sitp} - P_{gradient} \cdot (H_{A4} - H_{top})$ $\quad P_{top} = 5590psig$ _SITP at riser top of +67 ft elevation

Internal Design Pressure (B31.8)

$P_{ex} := 0psi$ _no external pressure

$P_i := P_{ex} + \dfrac{(2 \cdot Y \cdot t \cdot f_e \cdot F \cdot f_t)}{D}$ $\quad P_i = 7614psig$ _internal Design Pressure B31.8

CheckP$_{i1}$:= if($P_i > P_{sitp1}$, "OK", "Not OK") CheckP$_{i1}$ = "OK"

Hoop Stress during Hydrotest

$P_{ex} = 0psi$ _external pressure

$P_{fluid} := (H_{top} - H_{local1}) \cdot \gamma$ $\quad P_{fluid} = 2608psig$ _testing water head pressure

$P_{Hydro} := 1.25 \cdot P_{top} + P_{fluid}$ $\quad P_{Hydro} = 9595psig$ _minimum hydrotest pressure

$P_{Hydro\_max} := P_{Hydro} + 200 \cdot psig$ $\quad P_{Hydro\_max} = 9795psig$ _maximum hydrotest pressure

$P_{tnet\_max} := P_{Hydro\_max} - P_{ex}$ $\quad P_{tnet\_max} = 9795psig$ _maximum internal net test pressure

$SH := \dfrac{P_{tnet\_max} \cdot D}{2 \cdot t}$ $\quad SH = 65ksi$ _hoop stress, based on thin wall OD

$\%SMYS := \dfrac{SH}{Y}$ $\quad \%SMYS = 93\%$

CheckSH := if(%SMYS < 95%, "OK", "Not OK") CheckSH = "OK"

2. Hydrostatic Test Pressure and MAOP

The required hydrostatic test (hydrotest) pressure is 1.25 of the top SITP. The local test pressure should not be less than 1.25 of the local SITP. The effective hydrotest pressure is the net pressure the pipe experiences. For internal carrier pipe not subjected to hydrostatic pressure, the effective test pressure is the same as the hydrotest internal pressure. The Maximum Allowable Operating Pressure (MAOP) is the lowest of: a) Pipe Design pressure; b) 80% of Minimum Hydrotest Pressure and c) Minimum Design Pressure for Valves, Flanges, Fittings or other Components where applicable.

Effective Hydrotest Net Pressure

$P_{tnet} := P_{Hydro} - P_{ex}$ $\quad P_{tnet} = 9595psig$ _minimum hydrotest net pressure

$P_{eff} := P_{tnet}$ $\quad P_{eff} = 9595psig$ _effective test pressure

$P_{req} := 1.25 \cdot P_{sitp1} - P_{ex}$ $\quad P_{req} = 8061psig$ _required local net test pressure

CheckP$_{eff}$:= if($P_{eff} \ge P_{req}$, "OK", "Not OK") CheckP$_{eff}$ = "OK"

MAOP

$MAOP_{hydro} := 0.80 \cdot P_{eff} + P_{ex}$ _MAOP based on hydrotest pressure

$MAOP_{hydro} = 7676psig$

$P_{fittingH} := P_{fitting} + \gamma \cdot |H_{local1}|$ $\quad P_{fittingH} = 9228psig$ _design pressure for the components on sled at sled water depth

$MAOP := \min(MAOP_{hydro}, P_i, P_{fittingH})$ _MAOP at the calculation location

$MAOP = 7614psig$

CheckMAOP := if($MAOP \ge P_{sitp1}$, "OK", "Not OK") CheckMAOP = "OK"

Calculation 6. Flowline Carrier Pipe Pressure Design (3/3)

Location 2, Flowline at A-4 Sled

1. Internal Pressure Design

Local SITP Calculation

$P_{gradient} := \dfrac{P_{sitp} - P_{msl}}{H_{A4} - H_{msl}}$ $\quad P_{gradient} = -0.146 ft^{-1} psig$ $\quad$ *_pressure gradient assumption*

$P_{sitp2} := P_{sitp} - P_{gradient} \cdot (H_{A4} - H_{local2})$ $\quad P_{sitp2} = 6500 psig$ $\quad$ *_SITP at calculation location*

$P_{top} := P_{sitp} - P_{gradient} \cdot (H_{A4} - H_{top})$ $\quad P_{top} = 5590 psig$ $\quad$ *_SITP at riser top of +67 ft elevation*

Internal Design Pressure (B31.8)

$P_{ex} := 0 \cdot psig$ $\quad$ *_pipe is NOT exposed to external pressure*

$P_i := P_{ex} + \dfrac{(2 \cdot Y \cdot t \cdot f_e \cdot F \cdot f_t)}{D}$ $\quad P_i = 7614 psig$ $\quad$ *_internal Design Pressure B31.8*

$CheckP_{i1} := if(P_i > P_{sitp2}, \text{"OK"}, \text{"Not OK"})$ $\quad CheckP_{i1} = \text{"OK"}$

Hoop Stress during Hydrotest

$P_{ex} = 0 psi$ $\quad$ *_external pressure*

$P_{fluid} := (H_{top} - H_{local2}) \cdot \gamma$ $\quad P_{fluid} = 2763 psig$ $\quad$ *_testing water head pressure*

$P_{Hydro} := 1.25 \cdot P_{top} + P_{fluid}$ $\quad P_{Hydro} = 9751 psig$ $\quad$ *_minimum hydrotest pressure*

$P_{Hydro\_max} := P_{Hydro} + 200 \cdot psig$ $\quad P_{Hydro\_max} = 9951 psig$ $\quad$ *_maximum hydrotest pressure*

$P_{tnet\_max} := P_{Hydro\_max} - P_{ex}$ $\quad P_{tnet\_max} = 9951 psig$ $\quad$ *_maximum internal net test pressure*

$SH := \dfrac{P_{tnet\_max} \cdot D}{2 \cdot t}$ $\quad SH = 66 ksi$ $\quad$ *_hoop stress, based on thin wall OD*

$\%SMYS := \dfrac{SH}{Y}$ $\quad \%SMYS = 94\%$

$CheckSH := if(\%SMYS < 95\%, \text{"OK"}, \text{"Not OK"})$ $\quad CheckSH = \text{"OK"}$

2. Hydrostatic Test Pressure and MAOP

The required hydrostatic test (hydrotest) pressure is 1.25 of the top SITP. The local test pressure should not be less than 1.25 of the local SITP. The effective hydrotest pressure is the net pressure the pipe experiences. For internal carrier pipe not subjected to hydrostatic pressure, the effective test pressure is the same as the hydrotest internal pressure. The Maximum Allowable Operating Pressure (MAOP) is the lowest of: a) Pipe Design pressure; b) 80% of Minimum Hydrotest Pressure and c) Minimum Design Pressure for Valves, Flanges, Fittings or other Components where applicable.

Effective Hydrotest Net Pressure

$P_{tnet} := P_{Hydro} - P_{ex}$ $\quad P_{tnet} = 9751 psig$ $\quad$ *_minimum net hydrotest pressure*

$P_{eff} := P_{tnet}$ $\quad P_{eff} = 9751 psig$ $\quad$ *_effective test pressure*

$P_{req} := 1.25 \cdot P_{sitp2} - P_{ex}$ $\quad P_{req} = 8125 psig$ $\quad$ *_required local net test pressure*

$CheckP_{eff} := if(P_{eff} \ge P_{req}, \text{"OK"}, \text{"Not OK"})$ $\quad CheckP_{eff} = \text{"OK"}$

MAOP

$MAOP_{hydro} := 0.80 \cdot P_{eff} + P_{ex}$ $\quad$ *_MAOP based on hydrotest pressure*

$MAOP_{hydro} = 7801 psig$

$MAOP := min(MAOP_{hydro}, P_i)$ $\quad$ *_MAOP at the calculation location (no components at this location)*

$MAOP = 7614 psig$

$CheckMAOP := if(MAOP \ge P_{sitp2}, \text{"OK"}, \text{"Not OK"})$ $\quad CheckMAOP = \text{"OK"}$

Calculation 7. N3 Sled 5" Piping Pressure Design (1/3)

(All Pressures are gauge Pressures)

Constants

Sea Water Specific Weight	$\gamma \equiv 64 \cdot \text{lbf} \cdot \text{ft}^{-3}$
Modulus of Elasticity of Steel	$E \equiv 29000\,\text{ksi}$

Design Data

Outside Diameter for Pipe	$D = 5.563\text{in}$
Pipe Wall Thickness	$t = 0.75\text{in}$
SMYS of Pipe	$Y = 65\,\text{ksi}$
Water Depth at Well with the Maximum SITP	$H_{A4} = -6150\text{ft}$
Mean Sea Level Elevation (MSL)	$H_{msl} = 0\,\text{ft}$
Elevation at the Riser Top	$H_{top} = 67\,\text{ft}$
Water Depth at Calculation Location	$H_{local} = -6150\text{ft}$
Maximum SITP of the Flowline Loop, at Well A-4	$P_{sitp} = 6500\text{psig}$
Maxiumu SITP at Mean Sea Level Elevation	$P_{msl} = 5600\text{psig}$
Minimum Design Pressure of Sled Components	$P_{fitting} = 6650\text{psig}$
Construction Design Factor (B31.8) (Line Pipe)	$F = 0.72$
Longitudinal Joint Factor (DSAW or Seamless Pipe)	$f_e = 1$
Temperature Derating Factor (B31.8, Temp. <=250 F)	$f_t = 1$

Calculation 7. N3 Sled 5" Piping Pressure Design (2/3)

1. Internal Pressure Design

Local SITP Calculation

$P_{gradient} := \dfrac{P_{sitp} - P_{msl}}{H_{A4} - H_{msl}}$ $\quad P_{gradient} = -0.146 ft^{-1} psig$ $\quad$ *_pressure gradient assumption*

$P_{sitp1} := P_{sitp} - P_{gradient} \cdot (H_{A4} - H_{local})$ $\quad P_{sitp1} = 6500 psig$ $\quad$ *_SITP at calculation location*

$P_{top} := P_{sitp} - P_{gradient} \cdot (H_{A4} - H_{top})$ $\quad P_{top} = 5590 psig$ $\quad$ *_SITP at riser top of +67 ft elevation*

Internal Design Pressure (B31.8)

The sled piping is exposed to external pressure.

$P_{ex} := \gamma \cdot |H_{local}|$ $\quad P_{ex} = 2733 psig$ $\quad$ *_external pressure*

$P_i := P_{ex} + \dfrac{(2 \cdot Y \cdot t \cdot f_e \cdot F \cdot f_t)}{D}$ $\quad P_i = 15354 psig$ $\quad$ *_internal design pressure B31.8*

$CheckP_{i1} := if(P_i > P_{sitp1}, "OK", "Not OK")$ $\quad CheckP_{i1} = "OK"$

Hoop Stress during Hydrotest

The onshore hydrotest pressure for all the NaKika North Sleds is 8,300 to 8,350 psig based on approximately 1.25 times the minimum design pressure of the sled components. The required offshore hydrotest pressure is 1.25 times the SITP at riser top (+67ft). The Hoop Stress during hydrotest due to maximuminternal net pressure should not exceed 95% of SMYS.

A. Onshore Test

$P_{Hydro} := 8350 psig$ $\quad$ *_maximum allowable hydrotest pressure on Sled*

$P_{tnet} := P_{Hydro}$ $\quad P_{tnet} = 8350 psig$ $\quad$ *_internal net pressure*

$SH := \dfrac{P_{tnet} \cdot D}{2 \cdot t}$ $\quad SH = 31 ksi$ $\quad$ *_hoop stress, based on thin wall OD*

$\%SMYS := \dfrac{SH}{Y}$ $\quad \%SMYS = 48\%$

$CheckSH := if(\%SMYS < 95\%, "OK", "Not OK")$ $\quad CheckSH = "OK"$

Calculation 7. N3 Sled 5" Piping Pressure Design (3/3)

B. Offshore Test

$P_{ex} = 2733psig$		*_external pressure*
$P_{fluid} := (H_{top} - H_{local}) \cdot \gamma$	$P_{fluid} = 2763psig$	*_testing water head pressure*
$P_{Hydro} := 1.25 \cdot P_{top} + P_{fluid}$	$P_{Hydro} = 9751psig$	*_local minimum hydrotest pressure*
$P_{Hydro\_max} := P_{Hydro} + 200 \cdot psig$	$P_{Hydro\_max} = 9951psig$	*_maximum hydrotest pressure*
$P_{tnet\_max} := P_{Hydro\_max} - P_{ex}$	$P_{tnet\_max} = 7218psig$	*_maximum internal net test pressure*
$SH := \frac{P_{tnet\_max} \cdot D}{2 \cdot t}$	$SH = 27ksi$	*_hoop stress, based on thin wall OD*
$\%SMYS := \frac{SH}{Y}$	$\%SMYS = 41\%$	
CheckSH := if(%SMYS < 95%, "OK" , "Not OK")		CheckSH = "OK"

2. Offshore Hydrostatic Test Pressure and MAOP

The required hydrostatic test (hydrotest) pressure is 1.25 of the top SITP. The local test pressure should not be less than 1.25 of the local SITP. The effective hydrotest pressure is the net pressure the pipe experiences. For internal carrier pipe not subjected to hydrostatic pressure, the effective test pressure is the same as the hydrotest internal pressure. The Maximum Allowable Operating Pressure (MAOP) is the lowest of: a) Pipe Design pressure; b) 80% of Minimum Hydrotest Pressure and c) Minimum Design Pressure for Valves, Flanges, Fittings or other Components where applicable.

Effective Hydrotest Net Pressure

$P_{tnet} := P_{Hydro} - P_{ex}$	$P_{tnet} = 7018psig$	*_minimum hydrotest net pressure*
$P_{eff} := P_{tnet}$	$P_{eff} = 7018psig$	*_effective test pressure*
$P_{req} := 1.25 \cdot P_{sitp1} - P_{ex}$	$P_{req} = 5392psig$	*_required local net test pressure*
$CheckP_{eff} := if(P_{eff} \ge P_{req}, "OK", "Not OK")$		$CheckP_{eff} = "OK"$

MAOP

$MAOP_{hydro} := 0.80 \cdot P_{eff} + P_{ex}$		*_MAOP based on hydrotest pressure*
$MAOP_{hydro} = 8347psig$		
$P_{fittingH} := P_{fitting} + \gamma \cdot \lvert H_{local} \rvert$	$P_{fittingH} = 9383psig$	*_minimum design pressure for the components on sled at sled water depth*
$MAOP := min(MAOP_{hydro}, P_i, P_{fittingH})$		*_MAOP at the calculation location*
$MAOP = 8347psig$		
$CheckMAOP := if(MAOP \ge P_{sitp1}, "OK", "Not OK")$		CheckMAOP = "OK"

Calculation 8. N3 Sled 10" Pipe Spool Pressure Design (1/3)

(All Pressures are gauge Pressures)

Constants

Sea Water Specific Weight $\gamma \equiv 64 \cdot \mathrm{lbf} \cdot \mathrm{ft}^{-3}$

Modulus of Elasticity of Steel $E \equiv 29000\,\mathrm{ksi}$

Design Data

Outside Diameter for Pipe	$D = 10.75\mathrm{in}$
Pipe Wall Thickness	$t = 0.875\mathrm{in}$
SMYS of Pipe	$Y = 70\,\mathrm{ksi}$
Water Depth at Well with the Maximum SITP	$H_{A4} = -6150\mathrm{ft}$
Mean Sea Level Elevation (MSL)	$H_{msl} = 0\,\mathrm{ft}$
Elevation at the Riser Top	$H_{top} = 67\,\mathrm{ft}$
Water Depth at Calculation Location	$H_{local} = -6150\mathrm{ft}$
Maximum SITP of the Flowline Loop, at Well A-4	$P_{sitp} = 6500\mathrm{psig}$
Maxiumu SITP at Mean Sea Level Elevation	$P_{msl} = 5600\mathrm{psig}$
Minimum Design Pressure of Sled Components	$P_{fitting} = 6650\mathrm{psig}$
Construction Design Factor (B31.8) (Line Pipe)	$F = 0.72$
Longitudinal Joint Factor (DSAW or Seamless Pipe)	$f_e = 1$
Temperature Derating Factor (B31.8, Temp. <=250 F)	$f_t = 1$

Calculation 8. N3 Sled 10" Pipe Spool Pressure Design (2/3)

1. Internal Pressure Design

Local SITP Calculation

$P_{gradient} := \dfrac{P_{sitp} - P_{msl}}{H_{A4} - H_{msl}}$ $\quad P_{gradient} = -0.146ft^{-1}\,psig$ _pressure gradient assumption

$P_{sitp1} := P_{sitp} - P_{gradient}(H_{A4} - H_{local})$ $\quad P_{sitp1} = 6500psig$ _SITP at calculation location

$P_{top} := P_{sitp} - P_{gradient}(H_{A4} - H_{top})$ $\quad P_{top} = 5590psig$ _SITP at riser top of +67 ft elevation

Internal Design Pressure (B31.8)

The sled piping is exposed to external pressure.

$P_{ex} := \gamma \cdot |H_{local}|$ $\quad P_{ex} = 2733psig$ _external pressure

$P_i := P_{ex} + \dfrac{(2 \cdot Y \cdot t \cdot f_e \cdot F \cdot f_t)}{D}$ $\quad P_i = 10938psig$ _internal design pressure B31.8

$CheckP_{i1} := if(P_i > P_{sitp1}, "OK", "Not OK")$ $\quad CheckP_{i1} = "OK"$

Hoop Stress during Hydrotest

The onshore hydrotest pressure for all the NaKika North Sleds is 8,300 to 8,350 psig based on approximately 1.25 times the minimum design pressure of the sled components. The required offshore hydrotest pressure is 1.25 times the SITP at riser top (+67ft). The Hoop Stress during hydrotest due to maximuminternal net pressure should not exceed 95% of SMYS.

A. Onshore Test

$P_{Hydro} := 8350psig$ _maximum allowable hydrotest pressure on Sled

$P_{tnet} := P_{Hydro}$ $\quad P_{tnet} = 8350psig$ _internal net pressure

$SH := \dfrac{P_{tnet} \cdot D}{2 \cdot t}$ $\quad SH = 51ksi$ _hoop stress, based on thin wall OD

$\%SMYS := \dfrac{SH}{Y}$ $\quad \%SMYS = 73\%$

$CheckSH := if(\%SMYS < 95\%, "OK", "Not OK")$ $\quad CheckSH = "OK"$

Calculation 8. N3 Sled 10" Pipe Spool Pressure Design (3/3)

B. Offshore Test

$P_{ex} = 2733\text{psig}$		*_external pressure*
$P_{fluid} := (H_{top} - H_{local})\cdot\gamma$	$P_{fluid} = 2763\text{psig}$	*_testing water head pressure*
$P_{Hydro} := 1.25\cdot P_{top} + P_{fluid}$	$P_{Hydro} = 9751\text{psig}$	*_local minimum hydrotest pressure*
$P_{Hydro\_max} := P_{Hydro} + 200\cdot\text{psig}$	$P_{Hydro\_max} = 9951\text{psig}$	*_maximum hydrotest pressure*
$P_{tnet\_max} := P_{Hydro\_max} - P_{ex}$	$P_{tnet\_max} = 7218\text{psig}$	*_maximum internal net test pressure*
$SH := \dfrac{P_{tnet\_max}\cdot D}{2\cdot t}$	$SH = 44\text{ksi}$	*_hoop stress, based on thin wall OD*
$\%SMYS := \dfrac{SH}{Y}$	$\%SMYS = 63\%$	
$CheckSH := if(\%SMYS < 95\%, \text{"OK"}, \text{"Not OK"})$		$CheckSH = \text{"OK"}$

2. Offshore Hydrostatic Test Pressure and MAOP

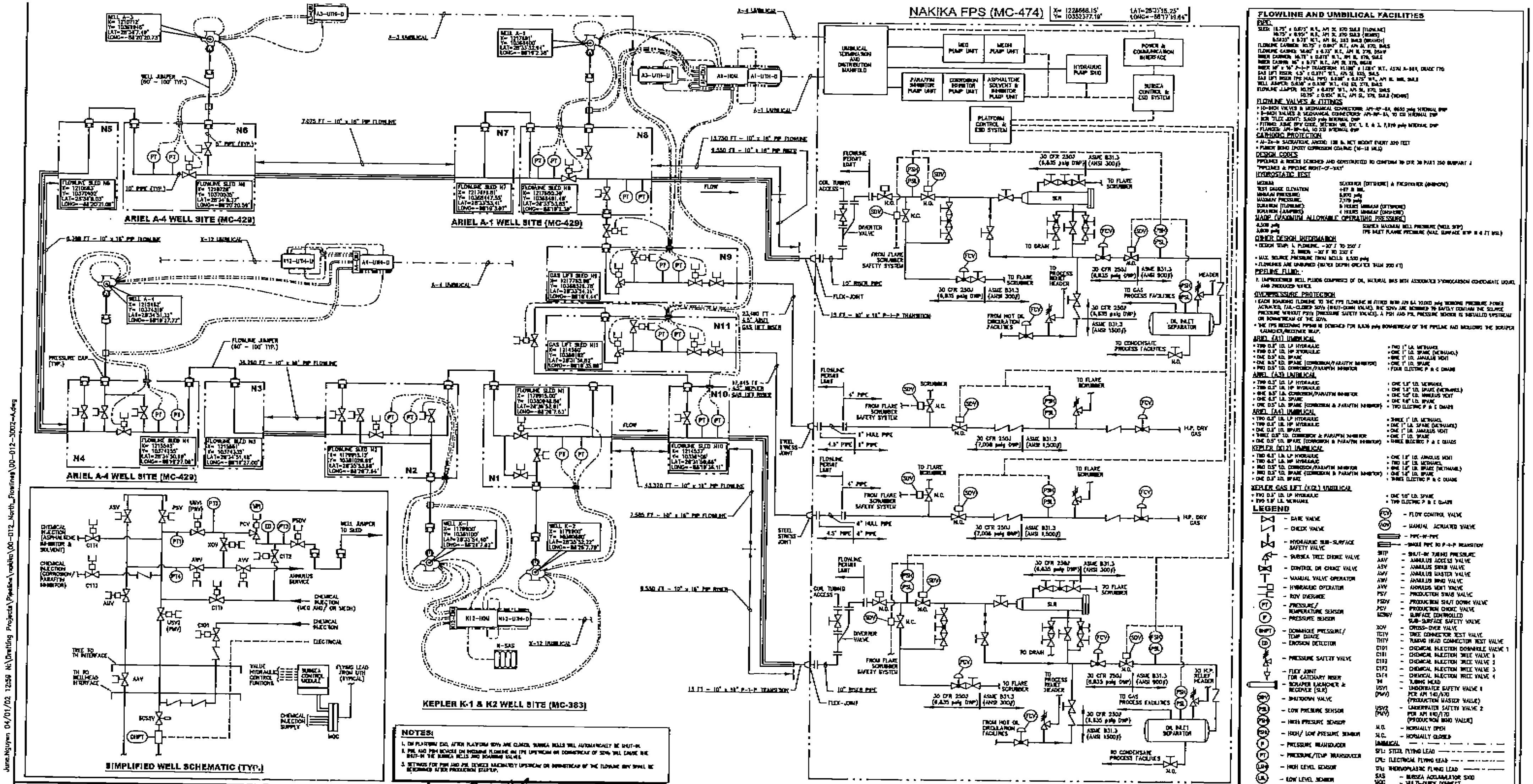
The required hydrostatic test (hydrotest) pressure is 1.25 of the top SITP. The local test pressure should not be less than 1.25 of the local SITP. The effective hydrotest pressure is the net pressure the pipe experiences. For internal carrier pipe not subjected to hydrostatic pressure, the effective test pressure is the same as the hydrotest internal pressure. The Maximum Allowable Operating Pressure (MAOP) is the lowest of: a) Pipe Design pressure; b) 80% of Minimum Hydrotest Pressure and c) Minimum Design Pressure for Valves, Flanges, Fittings or other Components where applicable.

Effective Hydrotest Net Pressure

$P_{tnet} := P_{Hydro} - P_{ex}$	$P_{tnet} = 7018\text{psig}$	*_minimum hydrotest net pressure*
$P_{eff} := P_{tnet}$	$P_{eff} = 7018\text{psig}$	*_effective test pressure*
$P_{req} := 1.25\cdot P_{sitp1} - P_{ex}$	$P_{req} = 5392\text{psig}$	*_required local net test pressure*
$CheckP_{eff} := if(P_{eff} \geq P_{req}, \text{"OK"}, \text{"Not OK"})$		$CheckP_{eff} = \text{"OK"}$

MAOP

$MAOP_{hydro} := 0.80\cdot P_{eff} + P_{ex}$		*_MAOP based on hydrotest pressure*
$MAOP_{hydro} = 8347\text{psig}$		
$P_{fittingH} := P_{fitting} + \gamma\cdot\lvert H_{local}\rvert$	$P_{fittingH} = 9383\text{psig}$	*_minimum design pressure for the components on sled at sled water depth*
$MAOP := min(MAOP_{hydro}, P_i, P_{fittingH})$		*_MAOP at the calculation location*
$MAOP = 8347\text{psig}$		
$CheckMAOP := if(MAOP \geq P_{sitp1}, \text{"OK"}, \text{"Not OK"})$		$CheckMAOP = \text{"OK"}$



Thomas Q. [illegible]
04-02-02

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NA KIKA NORTH FLOWLINES

OIL (10" x 16" PIP) FLOWLINE LOOP SAFETY SCHEMATIC & FLOWLINE DIAGRAM SUBSEA (MC-383) TO NAKIKA HOST (MC-474)

SCALE: NONE — 00-012-3002 — A

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